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June 2020

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Acronyms and Abbreviations

AC	Air Conditioning
ACEEE	American Council for an Energy-Efficient Economy
BCF	Billion Cubic Feet
Btu	British Thermal Units
CAISO	California Independent System Operator
CapEx	Capital Expenditures
CO_2	Carbon Dioxide
COP	Coefficient of Performance
CPP	Critical-Peak Pricing
CPUC	California Public Utilities Commission
DE	District Energy
DOE	U.S. Department of Energy
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effects
DWL	Deadweight Loss
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
GHG	Greenhouse Gas
H_2	Hydrogen
HGL	Hydrocarbon Gas Liquids
HVAC	Heating, Ventilation, and Air Conditioning
IRP	Integrated Resource Plan
KBH	Kay-Bailey Hutchinson
kW	Kilowatt
kWh	Kilowatt-Hour
ISO	Independent System Operator
LBNL	Lawrence Berkeley National Laboratory, or Berkeley Lab
LMP	Locational Marginal Price
LCFS	Low Carbon Fuel Standard
LCOE	Levelized Cost of Electricity
MCF	Million Cubic Feet
MECS	Manufacturing Energy Consumption Survey
Mlb	Thousand Pounds
$MtCO_2$	Million Tons of Carbon Dioxide
MW	Megawatt
MWh	Megawatt-Hour
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory

NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OpEx	Operating Expenditures
PAC	Program Administrator Cost (Test)
PCT	Participant Cost Test
PEM	Polymer Electrolyte Membrane
PG&E	Pacific Gas and Electric
PV	Photovoltaic
R&D	Research and Development
RIM	Rate Impact Measure (Test)
SCED	Security-Constrained Economic Dispatch
SCT	Societal Cost Test
SCUC	Security-Constrained Unit Commitment
SOx	Sulfur Oxides
SPP	Southwest Power Pool
T&D	Transmission and Distribution
TOU	Time-of-Use
TRC	Total Resource Cost (Test)
TWh	Terawatt-Hour
UCT	Utility Cost Test
USDA	U.S. Department of Agriculture
VRE	Variable Renewable Energy

Executive Summary

Many decentralized decision-makers on the demand-side may not yet have considered the implications of possible future changes to wholesale electricity price dynamics due to high shares of variable renewable energy (VRE) such as wind and solar power on the grid. These include the timing of when electricity is cheap or expensive, locational differences in the cost of electricity, and the degree of regularity or predictability in those costs. The purpose of this scoping report is to describe analytical methods for evaluating the sensitivity of demand-side decisions to different levels of VRE penetration ranging from a low of 5-20% to a high of 40-50% and to illustrate the susceptibility of some paradigmatic demand-side decisions to changes associated with high VRE growth. The principal question for this exploration is whether private and public electric-sector decisions that are made based on assumptions reflecting low VRE levels still achieve their intended objective in a high VRE scenario with 40-50% wind and solar? If the intended outcome may not be achieved with traditional approaches, what changes can be pursued to prepare for higher VRE scenarios?

Decisions in the electric sector are based on many different factors, but they often consider economic efficiency or some form of cost-benefit analyses. Changes in the characteristics of the power system brought about by higher VRE penetrations will result in altered wholesale power price dynamics that signal changing marginal system values to market participants. Previous work by Lawrence Berkeley National Laboratory (Berkeley Lab) developed hourly wholesale energy and capacity prices for four wholesale markets in the United States (CAISO, ERCOT, NYISO, and SPP) and contrasted the effects of historical VRE penetrations with 40 to 50 percent of wind and solar penetrations for 2030 scenarios. We found that the timing of very high electricity prices driven by system constraints will shift, average diurnal price profiles will change (especially with higher solar penetrations), and periods with very low (or even negative electricity prices) are likely to become both more frequent and longer lasting. We limit our decision analyses only to the marginal system value represented by the wholesale price series and do not include any additional electricity price components, such as transmission and distribution costs or demand charges.

This scoping report evaluates the impacts of changing patterns of peak system needs on the benefits of demand reductions by examining the altered value of different energy efficiency (EE) measures. Similarly, we investigate new opportunities that may arise from very low-priced wholesale electricity for large energy consumers. We calculate the value of new process investments (e.g., hydrogen production and other generalized electro-commodities), estimate the benefits of increased process flexibility that may use electricity as a process-input in addition to traditional fossil fuels (e.g., district energy systems), and showcase the varying value of new product storage investments (such as reservoir extensions at a desalination plant).

Finally, many decentralized decision-makers and end-use customers are not directly exposed to wholesale electricity prices but instead receive price signals from their retail electricity rates. As wind and solar shares increase, we compare the economic efficiency of flat retail rates relative to more dynamic time-of-use tariffs with and without critical peak-pricing events.

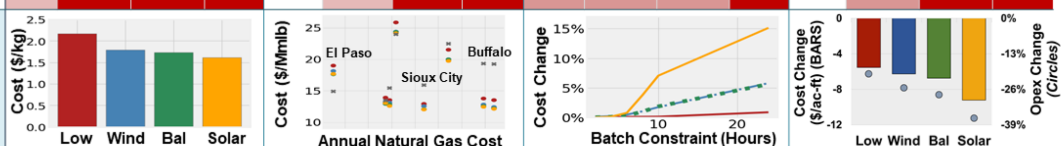
Table ES-1 highlights a subset of our findings and illustrates how some exemplary decisions will differ in low and high VRE environments.

Table ES-1. Summary of changes in economic performance of exemplary electric-sector decisions in low and high VRE scenarios

Decision Changes with 40%-50% Wind & Solar

(Wind: 30% wind & 10+% solar | Balanced: 20% wind & 20% solar | Solar: 30% solar & 10+% wind)

Impacts in 2030 relative to 2016		Southwest Power Pool 2016: 18% wind & 0% solar				NYISO (New York) 2016: 3% wind & 1% solar				CAISO (California) 2016: 7% wind & 14% solar				ERCOT (Texas) 2016: 16% wind & 1% solar			
		Low	Wind	Bal'd	Solar	Low	Wind	Bal'd	Solar	Low	Wind	Bal'd	Solar	Low	Wind	Bal'd	Solar
Relative value rankings of energy savings measures	Res HVAC	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Res Light	9	5	3	2	9	6	3	2	3	2	2	2	9	6	2	2
	Com HVAC	2	4	5	6	2	3	4	6	4	4	4	5	3	3	7	7
	Com Light	7	9	9	9	5	7	9	9	8	8	8	9	5	8	9	9
Declines in levelized per-unit costs of electricity-intensive products		Declining production costs (ex: H_2)				Greater value of fuel flexibility (ex: district heating)				Higher costs for inflexible processes (ex: industry)				Greater value for product storage (ex: desalination)			
Economic efficiency gains vs. flat rate	TOU2	57%	61%	64%	70%	50%	64%	66%	70%	76%	61%	68%	74%	61%	64%	81%	76%
	TOU3	60%	67%	72%	77%	47%	67%	71%	72%	77%	65%	70%	76%	63%	66%	84%	80%
	CPP + TOU3	99%	99%	99%	99%	95%	98%	97%	97%	99%	95%	96%	95%	93%	97%	93%	93%



Energy Efficiency Valuation

One goal of energy efficiency (EE) program design is to develop cost-effective portfolios that lower overall system costs. An EE program designer's decision is the relative portfolio share of investments in individual EE measures such residential lighting versus commercial heating, ventilation, and air conditioning (HVAC) efficiency. We find that the relative ranking of valuable EE measures changes with increasing VRE penetrations; while commercial HVAC and commercial lighting EE investments that provide load reductions during the middle of the day are very valuable in a low VRE environment, their relative attractiveness diminish with growing solar generation shares. In contrast, load reductions of more efficient residential lighting increase in their relative value as wholesale electricity prices now tend to rise in the early evenings.

Opportunities for Large Energy Consumers

Large energy consumers can benefit from changing electricity price dynamics and increased frequencies of very low-price events if they can access wholesale electricity markets (or at least have retail rates that reflect the new price patterns) and if they can substitute electricity for other energy inputs in their production processes. Given the long design life of many industrial capital investments, decision-makers may benefit from evaluating closely whether their typical investment assumptions still lead to cost-effective outcomes in high VRE futures.

Hydrogen Production and Other New Electro-Commodities

We find opportunities for some industries that can use electricity to create new intermediate energy and chemical products. Commodities with capital costs representing the dominant share of all-in product costs will not see large changes in levelized cost between low and high VRE scenarios, as energy costs make up only a minor share of the product costs. The decision whether to produce such commodities will consequently *not* substantially hinge on the potential pathway of VRE penetration levels. In contrast, the levelized cost of commodities with lower capital cost shares and higher energy cost shares diverges strongly in low versus high VRE scenarios. Cost-optimal operation can lead to a strong reduction in hours of production in high VRE scenarios, especially in solar dominated scenarios, enabling substantial savings in per-unit costs. A case study looking at power-to-hydrogen (H_2) production found optimal utilization rates fall, for example, from 80 percent to only 27 percent in CAISO's high solar scenario. Less flexible production processes that require longer consecutive batch runtimes may see lower savings. Industrial research efforts may consequently shift some of their focus in a high VRE scenario from increasing process efficiency to lowering capital costs and increasing production flexibility. The CAISO electrolyzer example again shows cost reductions from a 10 percent efficiency improvement equal about 9 percent in both low and high solar scenarios, while a 10 percent capital cost improvement corresponds to cost reductions of about 6 percent in a high solar scenario and only 1 percent in a low VRE scenario. Overall, we observed hydrogen production costs falling with growing VRE penetrations, depending on the region, by 13 to 40 percent.

Groundwater Desalination and The Role of Product Storage

While there is much focus on energy storage to smooth out the variability of wind and solar generation, many end use processes also can deploy storage on the product end to manage price variability; perhaps even more cost-effectively than electricity storage, for example, in batteries. Long intervals of very low wholesale electricity prices may induce industrial end users to produce more of a product (commodities, treated water, or heat) during low-cost hours, place it into storage, and discharge it from storage during high-cost hours. A case study examining brackish water desalination in El Paso, Texas, reveals that the largest component of the levelized cost of desalinated water is the upfront capital investments of the desalination plant itself, and even sizeable savings in operational costs reduce the delivered water costs only modestly. Nevertheless, operational savings from investing in additional product storage are nearly twice as high with growing VRE shares, especially in the high solar scenario (37 percent relative to about 20 percent in the low VRE scenario), and the optimal storage reservoir size nearly doubles.

Utilization rates of storage (the number of hours of pumping into storage) are also highest in the high solar VRE scenario (19 percent) followed by the balanced (11 percent) and high wind (6 percent) VRE scenarios, which correspond closely to the percentage of hours featuring prices less than $5 per megawatt-hour (MWh).

District Energy Systems with Increased Fuel Flexibility

Existing industrial processes that rely primarily on one or more fossil fuels (e.g., natural gas and oil) may benefit economically from the flexibility to switch the source of input energy to electricity during low price periods in a high VRE scenario. Case studies for college campuses throughout the United States show that systems with high gas expenses benefit from operating heat pumps at times instead of gas boilers. In contrast, campuses with low gas expenses cannot achieve high enough operational savings to make up for the increased upfront capital investments.

Retail Rate Design

Retail electricity rates seek a balance between providing transparent price signals to electricity consumers (economic efficiency) and maintaining relatively predictable and simple rate structures that customers can understand and respond to. In our analysis, we utilize deadweight loss as a measure of economic inefficiency. By this definition, dynamic retail rates that reflect wholesale electricity prices with different time-of-use periods tend to be more efficient than flat rates; however, their relative benefit increases dramatically in a high VRE environment (e.g., from an average factor of 2.8 in a low VRE scenario to 4.3 in a high VRE scenario). Growing wind and especially solar shares also have strong impacts on the best choice of peak versus off-peak periods that are used in time-of-use periods. Optimizing high versus low price periods for a low VRE environment and not updating them regularly to reflect changing price patterns can lead to even worse economic efficiency than maintaining flat rates. Appropriately calibrated retail rates that feature, for example a new super-off peak period in the middle of the day, can bring large economic efficiency gains in a high solar scenario.

1 Introduction

Many long-lasting decisions for supply- and demand-side electricity infrastructure and programs are based on historical observations or assuming a business-as-usual scenario with low shares of variable renewable energy (VRE). If the share of VRE increases significantly, however, fundamental characteristics of the power system will change. These include the timing of when electricity is cheap or expensive, locational differences in the cost of electricity, and the degree of regularity or predictability in those costs. Many of these changes can be observed through changes in the patterns of wholesale prices, and initial impacts are already being observed internationally and in some regions of the United States where high instantaneous penetrations of wind and solar are already a regular occurrence.

These price shifts can have indirect effects on other demand- and supply-side resources in the electricity sector, particularly if their demand or supply characteristics are inflexible and long-lasting (i.e., cannot change easily over the short-term in response to changing wholesale price patterns). Our research is motivated by one question: *Will private and public electric-sector decisions that are made based on assumptions reflecting low VRE levels of 5-20% still achieve their intended objective in a high VRE scenario with 40-50% wind and solar?*[1]

This scoping report offers tangible examples for how changing wholesale price patterns can be considered and highlights types of decisions particularly impacted by high levels of VRE. Specifically, we examine the effects of higher VRE penetrations on energy efficiency valuation in Section 2, large electricity consumers and emerging applications in Section 3, and electricity retail rate design in Section 4. The following paragraphs describe the common analytical framework that we apply to each of the three fields when evaluating the effects of higher wind and solar penetrations.

1.1 Analysis Framework for Demand-Side Decisions

For discussion of VRE impacts we follow a common structure, first describing the broad objectives of decision-makers in each field and portraying how VRE growth may affect them. We then illustrate qualitatively common decision-making processes in each field and discuss how stakeholders weigh different options. Subsequently we conduct a quantitative analysis that describes performance changes across different VRE scenarios and that highlights the decision aspects most sensitive to different VRE penetrations. We conclude each topic with a discussion of potential changes to program design that ensure stakeholder objectives continue to be met in high VRE scenarios.

Decisions about demand-side programs in the electric sector are complex and incorporate many different considerations brought forward by stakeholders, including economic efficiency, equity concerns, or specific goals (e.g., increasing electric vehicle adoption). While we recognize this

[1] Low VRE levels are defined as holding fixed the 2016 penetration level of VRE in each ISO region: 18% wind/0% solar in SPP, 3% wind/1% solar in NYISO, 7% wind/14% solar in CAISO, 16% wind/1% solar in ERCOT.

cornucopia of valid perspectives, the analysis focuses primarily on economic efficiency evaluations. During regulatory decision-making processes these are often informed by cost-effectiveness tests that weigh possible value streams of new investments or policies against the associated new expenditures.

As the electric system continues to evolve, the shifting overall power system dynamics can in turn affect the value proposition of various demand-side assets and their cost-effectiveness. Our scoping analysis concentrates on the value changes brought about by increasing levels of VRE penetration, and wholesale electricity prices are used as a proxy for the changing marginal system value. By choosing wholesale prices as the value driver, we exclude a variety of other value considerations that may be relevant for decision-makers. We do not examine value streams that are a result of (deferred) transmission and distribution (T&D) system investments; we limit our analysis of environmental externalities and exclude broader economic impacts. Overall, we embrace a system value perspective in this analysis, and analyze the private cost-benefit calculations of an end-use customer only in Section 3, when discussing investments of large electricity consumers. Figure 1 summarizes the role of system value assessments in the context of the broader decision-making process.

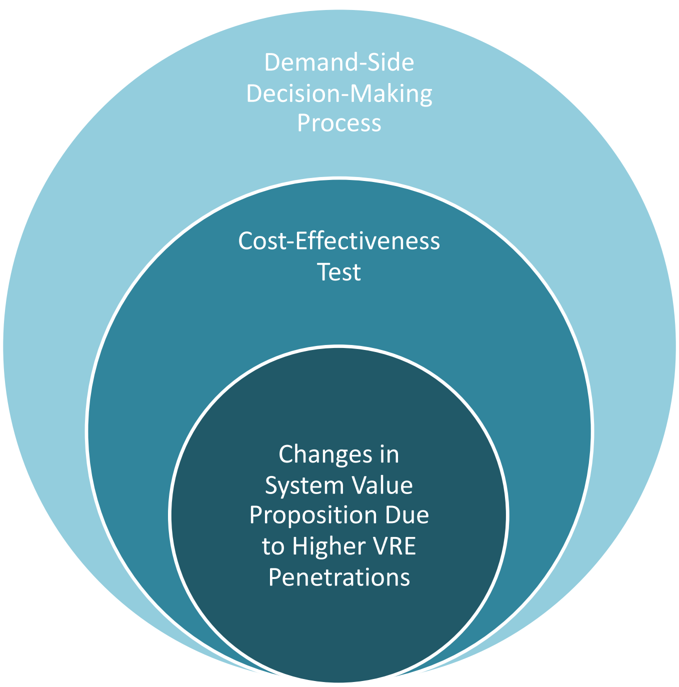


Figure 1. Relevance of system value changes for demand-side decisions

1.2 Simulation of Energy and Capacity Values in a High VRE Scenario

As a foundational step, we first developed a common set of wholesale electricity prices from detailed wholesale electric market simulations with low and high VRE scenarios (Seel, Mills, and Wiser 2018). The simulations focused on the year 2030 in four regions or Independent System Operators (ISOs)—the Southwest Power Pool (SPP), New York Independent System Operator

(NYISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)—across four scenarios: (1) a low VRE penetration scenario that freezes renewable energy shares at 2016 levels, (2) a high solar scenario (featuring 30 percent solar energy and at least 10 percent wind), (3) a high wind scenario (featuring 30 percent wind energy and at least 10 percent solar), and (4) a balanced scenario (20 percent wind and 20 percent solar). As price responses are sensitive to broader regional exchanges of electricity, we assume neighboring markets also achieve 40 percent VRE penetration in the high VRE scenarios. We do not include any cost of curtailment; in effect we assume no incentive for any generator to produce power when wholesale electricity prices are below $0/megawatt-hour (MWh).[2]

The wholesale price simulation leverages two commercial tools developed by LCG consulting that were chosen because of their credible representation of long-run marginal cost that allow for high temporal variation in energy prices, consistent ancillary service prices, and their history of frequent usage by decision makers for asset valuation and planning.

The analysis uses first a capacity expansion model and optimization tool, Gen-X,[3] where capacity expansion (including the option to retire existing generation) is based on social cost minimization, including the variable and ongoing fixed cost of all generators and up-front capital costs for new generators. For each scenario, Gen-X is used to find the least-cost combination of generation additions and retirements while satisfying system constraints.[4] In this analysis, Gen-X was only used to find the expansion plan for non-VRE resources, as the VRE levels were specified exogenously. We include emission costs for nitrogen oxides (NO_x), sulfur oxides (SO_x) in NYISO and ERCOT, and carbon dioxide (CO_2) in CAISO ($53/ton) and NYISO ($24/ton), based on exogenous projections of permit prices by planning entities in each of the four regions.[5,6] The emissions costs affect the marginal costs of generators and therefore influence the market clearing prices for electricity.

After establishing a generation portfolio in each of our scenarios, we subsequently derive hourly zonal electricity price and marginal emission rate series using a security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) tool developed by LCG Consulting called the UPLAN Network Power Model.[7] This model co-optimizes energy and ancillary service (AS) markets and allows for a large range of input data for load, generation, and the transmission network. The energy and AS prices are subsequently used to simulate rational bids for a capacity market. One consequence of the sequential nature of the capacity expansion modeling followed by the detailed market modeling is that the capacity prices reflect the largest unmet fixed operation and maintenance (O&M) costs of any unit in the market, or the largest

[2] We assume that most wind projects will not receive production tax credits by 2030 and disregard additional incentives such as voluntary or mandatory renewable energy credits, or financial power purchase agreement (PPA) arrangements that would motivate VRE generators to schedule electricity at negatives prices.
[3] For more documentation, see LCG Consulting (2017a).
[4] System-level constraints in Gen-X include (but are not limited to) planning reserve margins, load and ancillary service requirements, Renewable Portfolio Standards (RPS) and emission constraints, and area power transfer limits.
[5] Based on California Energy Commission (2016).
[6] Based on New York Independent System Operator (2016).
[7] For more documentation see LCG Consulting (2017b).

unmet fixed capital costs and fixed O&M costs of new units built to meet the planning reserve margin in Gen-X. We allocate the capacity prices in equal parts to the top 100 peak net load hours for each respective region and add them to the energy prices for our decision analyses.

Our wholesale market simulations summarized in Figure 2 show a general decrease in average annual hourly wholesale energy prices by $5–$16/MWh. Very low-priced hours below $5/MWh become much more ubiquitous (approaching 20 percent of all hours of the year in the high solar scenario in ERCOT), diurnal price profiles change substantially depending on the high VRE scenario, and overall energy price volatility increases. We also find a general increase in regulation and spinning reserve prices by a factor of two to eight, but we do not evaluate AS market participation by the resources examined in the remainder of this report and consequently disregard them here. Peak net-load hours associated with a high capacity value tend to shift later into the evening and accrue over a shorter range of hours while occurring over a larger set of days. For more details and the underlying raw data of this first part of our project, please see https://emp.lbl.gov/publications/impacts-high-variable-renewable.

Wholesale Price Effects of 40%-50% Wind & Solar

(Wind: 30% wind & 10+% solar | Balanced: 20% wind & 20% solar | Solar: 30% solar & 10+% wind)

Impacts in 2030 relative to baseline with 2016 wind & solar shares	**Southwest Power Pool** 2016: 18% wind & 0% solar			**NYISO (New York)** 2016: 3% wind & 1% solar			**CAISO (California)** 2016: 7% wind & 14% solar			**ERCOT (Texas)** 2016: 16% wind & 1% solar		
	Wind	Balanced	Solar	Wind	Balanced	Solar	Wind	Balanced	Solar	Wind	Balanced	Solar
Lower Average Prices [$/MWh]	-19%	-21%	-27%	-37%	-38%	-39%	-25%	-23%	-27%	-25%	-17%	-15%
More Hours <$5/MWh In baseline: 0% of all hours	6%	8%	13%	2%	7%	11%	6%	7%	11%	6%	11%	19%
Changes in Diurnal Price Profile red baseline shows 2016 wind & solar shares												
More Price Variability	1.8x	2.1x	2.5x	2.1x	2.3x	2.5x	3.0x	2.9x	3.4x	1x	4.7x	6.6x
Higher AS Prices Regulation Down	5x	6x	9x	2x	2x	3x	3x	3x	3x	2x	3x	4x
Change in Timing of Top Net-Load Hours	Shift from 4pm to 7pm			Shift from 3pm to 5-7pm			No further shift 7pm			Shift from 3pm to 6-8pm		

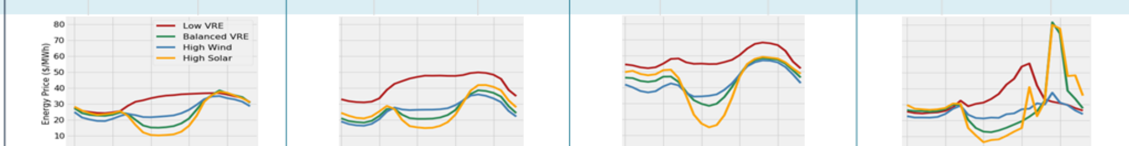


Figure 2. Wholesale price effects of high VRE scenarios

2 Energy Efficiency Valuation

2.1 Introduction

With the possibility that an increased share of VRE will introduce fundamental changes to the characteristics of the power system, energy efficiency programs may also need to change, in order to continue to achieve their intended objectives of lowering overall power system costs in high VRE scenarios. In this section, we explore how decisions about energy efficiency (EE) programs may be affected by changes from a low VRE scenario to a high VRE scenario.

Efficiency programs offer value by decreasing overall load levels, thereby reducing stress to the system at times of peak demand. With the addition of large amounts of VRE, the relative timing of when peak net-load levels occur can change, and consequently the timing of when it is most valuable to reduce energy consumption may also change. Different EE measures have distinct saving shapes, therefore, growth in wind and solar can increase or decrease alignment of specific EE measures with the times of highest system value. Given these changes in wholesale system price patterns, we investigate how an EE program designer may want to shift the constituent parts of their EE portfolio to ensure that savings continue to accrue at times of high system value.

Energy efficiency investments take many forms in the United States. Largely the investments are driven by building codes for new or retrofitted buildings, appliance and equipment efficiency standards, conventional contracting work, energy service performance contracts, and ratepayer funded energy efficiency programs. Dedicated EE policies and programs are deemed necessary to overcome an underinvestment in energy efficiency deriving from a number of well-recognized barriers, including market aspects (e.g., split-incentives and transaction costs), customers (information, awareness, and funding availability), and regulations (utility financial disincentives, a non-level playing field with supply-side resources in energy planning processes, or an information deficit in EE programs) (DOE and EPA 2006). As a result of this historical underinvestment, it is estimated that between 2016 and 2035 the equivalent of more than 15 percent of the 2035 U.S. retail sales can still be targeted cost-effectively by energy efficiency measures (EPRI 2017), A different estimate pins the economic potential to 22 percent of residential electricity consumption by 2035 (Wilson et al. 2017).

Energy efficiency measures are diverse, and deciding the relative weight of different efficiency measures is an important task in developing an EE program, and subsequently, an EE portfolio consisting of multiple EE programs. Optimal measure selection depends significantly on the other available supply- and demand-side energy resources, as they determine the value of EE savings. With changing energy resource options and changing peak and off-peak periods, the relative share in the efficiency portfolios of near-constant load reduction measures (e.g., more efficient refrigerators), traditional off-peak measures (such as street lighting or residential lighting), or traditional on-peak measures (such as high efficiency air conditioning units in office spaces) may need to change in order to continue the most cost-effective resource selection from a utility perspective and prevent misaligned EE investments. An analysis of how the cost-effectiveness of some EE measures may change over their lifetimes is particularly important, given the longevity of these infrastructure investments.

This analysis focuses on utility customer-funded residential and commercial EE programs, although our key takeaways will also provide insights for other EE investments. Efficiency programs can differ significantly in their design and goals across states and utilities, but the primary task of EE program administrators is to select and implement a combination of EE measures that result in lower utility system cost (e.g., the production and delivery of energy, capacity, and ancillary services) than would occur when providing those same services with other resources.

In this section, we first describe the objectives of EE programs and explain how decisions about them are often made. We then conduct a quantitative analysis to illustrate how the system value of various EE measures changes across our low and high VRE future scenarios. The changes in the system value of EE shows which measures are more likely to be sensitive to different VRE scenarios, and that knowledge can inform potential changes to program design for high VRE scenarios.

2.2 Qualitative Summary of the Decision-Making Process

Decisions about utility customer-funded EE programs are often complex, as they balance multiple objectives such as economic efficiency, equity considerations among different customer groups, or specific policy goals such as reductions in peak demand and air pollutant emissions or technology development.

The specific design of new EE programs usually involves a sequence of assessments that are illustrated in Figure 3. First, the technical potential of new EE investments (all resources that are technologically feasible) is characterized, followed by a narrower determination of the economic potential, which includes all EE investments that pass cost-effectiveness tests based on defined costs and benefits. A further down-selection needs to take into account what potential is actually achievable within a certain time horizon, given adoption and market barriers, as well as funding constraints (NAPEE 2007). From this achievable EE potential a program designer then selects the EE measures that will be targeted by a specific EE program.

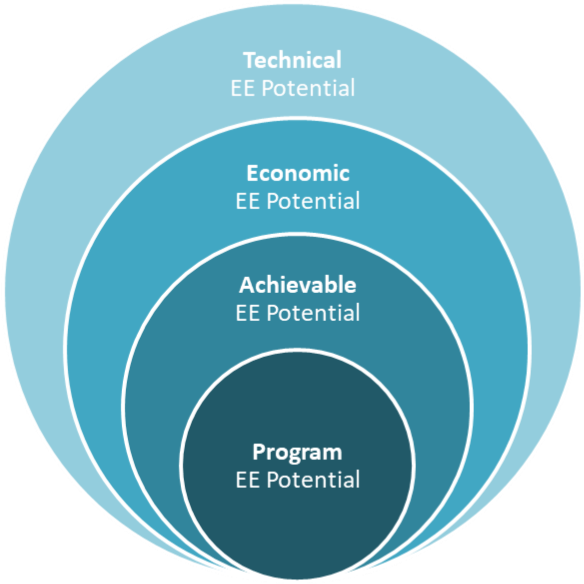


Figure 3. Selection process of EE measures for program inclusion

Economic cost-effectiveness tests of EE investments are thus an important part of the decision process and have existed in a formalized manner for more than 35 years.[8] Since then many sophisticated assessments of the economic EE potential have been developed throughout the United States; a recent aggregation of studies since 2007 by the U.S. Department of Energy (DOE 2017) is offered for example.

The vast majority of states rely on the Total Resource Cost Test (TRC Test) when they evaluate the costs and benefits of EE measures to the utility and ratepayers (ACEEE 2016). For the TRC, most states limit the inputs of the benefits-side of the equation to avoided utility energy and capacity costs. Energy-related avoided costs are either represented by the forecast of future average market prices in organized wholesale electricity markets (such as CAISO, ERCOT, SPP, and NYISO) or as the levelized cost of energy (LCOE) of a new power plant for vertically integrated utilities (including fuel, capital, fixed operation, maintenance, and periodic capital replacement costs). Capacity-related avoided costs often include capital, fixed operation, maintenance, and periodic capital replacement costs of a proxy peaking unit. Depending on the location and avoided cost methodology, this value may alternatively be based on the marginal capacity value of the system (Mims, Eckman, and Goldman 2017).

The TRC test can also include gas and water savings, and other monetized non-energy benefits that are internalized in the utility revenue requirement such as avoided environmental compliance costs (e.g., air pollutant emissions costs), T&D capacity costs, avoided line losses, and reductions in reserve requirements (Lazar and Colburn 2013; Mims, Eckman, and Goldman 2017). These direct benefits are usually evaluated over the measure's useful lifetime on a net-present-value or levelized cost-benefit basis. Other indirect benefits might include less exposure to risk (e.g., fuel price volatility), demand reduction induced price effects (DRIPE), or secondary

[8] See, for example, California's 1983 manual Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs.

obligations such as renewable energy shares of retail electricity. Taking this more expansive view is important, as non-energy benefits can be as large or greater than energy benefits alone (ACEEE 2018; Myers and Skumatz 2006; Neme and Kushler 2010).

An alternative to the TRC is the Societal Cost Test (SCT), which is more comprehensive and may include in addition to the TRC benefits other non-monetized values such as air quality improvement, employment impacts, and broader economic development impulses. Other far less commonly used cost-effectiveness tests include the Utility Cost Test (UCT), the Program Administrator Cost Test (PAC Test), the Participant Cost Test (PCT), or the Rate Impact Measure Test (RIM Test) (ACEEE 2018; Kushler, Nowak, and Witte 2012).

When it comes to assessing any of these above-mentioned value streams, three important trends have developed in recent years: (1) increased geographic granularity, (2) using data sets with higher time resolutions, and (3) employing an integrated forward-looking optimization that evaluates efficiency measures in the context of other demand- and supply-side resources across multiple scenarios (Mims Frick, Schwartz, and Taylor-Anyikire 2018).

Historically EE measures have been evaluated primarily as system-level load reductions, and this macro-perspective is still the most common today. However, over the past few years increasing attention has been placed on the locational benefits that efficiency can offer, using analyses with much higher geographic granularity (Mihlmester and Fine 2016). The value of energy efficiency measures, specifically their ability to defer investments in distribution grids, can vary substantially depending on the existing infrastructure utilization, the network configuration, and the precise siting of load reducing measures. Capturing these position-dependent value streams appropriately is essential when determining the suitability of EE for “non-wire solution” projects. Locational net-benefit analyses of efficiency play an important role in distribution system planning studies (Cooke, Homer, and Schwartz 2018; De Martini, Kristov, and Schwartz 2016; Homer et al. 2017; ICF 2018). Including efficiency in these infrastructure plans is required by regulators in California, Nevada, New York, and Hawaii (Black & Veatch 2017; NY DPS 2018; Schwartz and Mims Frick 2019).

A second trend is to incorporate better temporal perspectives in cost-effectiveness studies of efficiency measures. Higher quality data provided by advanced metering infrastructure can contribute to an increasing shift from average valuations to time-sensitive valuations for EE measures (Boomhower and Davis 2016; Mims, Eckman, and Goldman 2017; Mims, Eckman, and Schwartz 2018; Stern 2013). In contrast to earlier analyses that utilize annual or seasonal average energy costs (differentiated by broad peak- versus off-peak categories), new valuation analyses can leverage higher resolution time series with hourly energy and capacity values of different EE measures (see, for example, Minnesota’s recent EE potential study [Center for Energy and Environment 2018]).

An extension of time-dependent valuation is a truly integrated forward-looking assessment of EE measures. Traditionally, program designers relied on historical records to create “coincidence factors” and “diversity factors” for state technical reference manuals. However, a recent edition of the *National Standard Practice Manual* suggests switching from backward- to forward-looking evaluations (Woolf et al. 2017). Utilities include EE measures in their load demand curve modeling during their periodic Integrated Resource Plans (IRPs)—in most cases as a load decrement and in a few instances explicitly as a resource (Bryson and Mansueti 2011; Lamont and Gerhard 2013). The optimization of efficiency portfolios with dynamic calculations of avoided costs can showcase the large cost-saving opportunities that EE (and more versatile demand response [DR]) present (Bistline 2017; Potter, Stuart, and Cappers 2018), especially when long-run avoided system costs are considered that fully internalize efficiency contributions over the useful lifetime of an EE measure. While IRP modeling can in principle assess EE portfolio performance across different future scenarios, through sensitivities and Monte Carlo simulations, this is not yet standard for most utilities. Evaluated scenarios often focus on EE measure characteristics (e.g., customer adoption pathways) instead of energy system scenarios that feature, for example, high variable renewable penetration cases.[9]

The results of this scoping study should be considered primarily as a way to explore how energy efficiency valuation may change in response to changing price dynamics with high VRE scenarios, and not as an authoritative assessment of what measures are ultimately cost-effective and which should be included in efficiency portfolios. More detailed analysis would be required to assess how changing efficiency value compares to the required investment costs to enable our assumed savings. Similarly, further analysis would benefit from using more diverse end-use saving shapes and assessing additional demand flexibility potential.

2.3 Quantitative Analysis of Performance Changes under High VRE Penetrations

Analytical Approach

System Value Calculation

To inform the question of whether EE program designs may change under high VRE scenarios, we conduct a quantitative assessment of how the system value of different EE measures changes across varying levels of VRE penetration. We select a diverse set of EE measures and calculate the system value for each measure in four market regions of the United States under a low VRE scenario and three high VRE scenarios. Careful consideration of future net load-shape and resource changes to the system is most important for EE measures whose value is sensitive to the choice of VRE scenario.

[9] Examples of entities that incorporate EE as a resource in integrated assessments include the 7th Power Plan by the Northwest Power & Conservation Council that uses their Regional Portfolio Model to evaluate the cost-effectiveness of energy efficiency supply curves representing over 1400 measures compared to other supply side resources across 800 different future conditions (NWPCC 2016). PacifiCorp's 2015 IRP evaluates 27 bundles, grouped by cost and load shape, on an hourly basis. Puget Sound Energy used an EE supply curve analysis to quantify the energy and peak demand savings potential as part of their IRP process with very high geographic granularity (down to ZIP-code level) (PSE and Navigant 2017). California increasingly moves toward a unified analysis framework of distribution resource planning and system-level IRPs with high VRE projections (CPUC 2016) that explicitly include efficiency as a resource. Specifically, the California Public Utilities Commission (CPUC) calls for integrated assessment principles of energy efficiency, uses scenario analyses (CPUC & Navigant 2017), and promotes efficiency measures that enable more flexible demand response assets (CPUC 2018).

To be clear, we do not replicate the entire decision-making process of EE utility programs. Instead our analysis is limited to an aspect of cost-effectiveness testing, namely a comparison of the energy and capacity value proposition of EE measures in response to increasing wind and solar penetrations. Our approach is justified in part, as the cost of different EE measures is not likely to change with VRE scenarios, in contrast to changes in system value. However, measure costs and other value attributes excluded from our analysis are important for the final selection of an optimal EE portfolio (see below).

As described in the qualitative summary of the decision-making process of EE utility programs, the emerging *time-dependent valuation* approach of EE measures is particularly promising for energy systems that feature large value variations over diurnal cycles or seasons. We will follow this approach in our system value calculation, focusing on energy and capacity values. In particular, we estimate the time-dependent system value of an EE measure as the product of the time-varying EE savings and the time-varying wholesale electricity price, summed over the year.

We use simulated hourly energy and capacity prices (attributed to the top 100 peak net-load hours) for this time-sensitive valuation of energy efficiency measures, which are described in the introduction of this scoping report (Seel, Mills, and Wiser 2018).

Limitations

In the system value calculations, we focus on energy and generation capacity values, which also incorporate some environmental benefits to the extent that they are subsumed in wholesale electricity prices, such as the NOx and SOx permit prices and the assumed carbon price in the markets of CAISO and NYISO. However, these value streams include only a subset of the potential value streams enumerated in the economic cost-effectiveness discussion above, as described in Figure 4.

Unfortunately, we lack the necessary data to assess the complete system value of EE measures. Our model output does not include detailed T&D system data for the year 2030 that could be used to analyze deferral value of that infrastructure.

Furthermore, we do not perform a fully integrated value assessment as some of the sophisticated IRPs do. Those assessments iteratively build out cost-effective EE measures or account for evolving appliance codes and standards in the capacity expansion phase, which in turn may affect aggregate system load shapes (thereby influencing wholesale electricity prices instead of just being a price-taker). As a result, not all cost-effective EE investments have been made in our simulated year 2030. Our analysis focuses instead on a *marginal value assessment* that quantifies the value of the next unit of EE savings—this number may overstate the realized value if a significant amount of EE would have already been deployed; it is not the same as the average value of all EE investments.

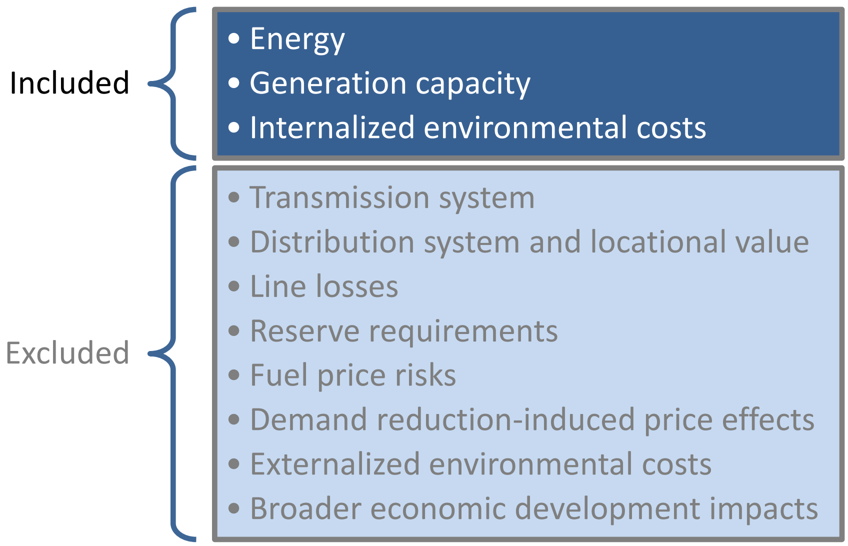


Figure 4. Included value streams in the EE benefit analysis

Our overall number of scenarios is also limited. We perform scenario analyses to look at the EE value in a low VRE baseline, a high wind scenario, a high solar scenario, and a balanced wind/solar combination. We do not, however, account for different load growth, EE technology evolution, EE uptake, or fuel cost pathways. We do not perform detailed Monte Carlo simulations that would investigate the impact of these variables. Finally, we focus only on the single year 2030, which may not be fully representative of average future years (weather-induced load variations), and we do not describe the broader system evolution beyond the year 2030. Consequently, we do not capture the changing value of EE measures over time and beyond our modeled system conditions.

Because of these limitations, the focus of this quantitative assessment is on relative performance changes and the sensitivity of EE measures to VRE induced wholesale energy price changes, instead of changes in the total costs and benefits of EE that would be used in detailed cost-effectiveness studies.

Energy Efficiency Measures

Data sources

Only very limited empirical data are publicly available that describe EE savings profiles with high geographic and temporal resolution (Mims, Eckman, and Schwartz 2018).[10] Instead we follow the common practice of assuming that EE measures lead to a percentage reduction in energy intensity but do not alter the underlying end-use load shape (Mims, Eckman, and Goldman 2017). This approach is defensible as long as EE measures do not represent a change in the underlying technology (e.g., a switch from electric resistance heating to heat-pump heating). While this has been the traditional practice among EE program designers, future EE programs that incorporate

[10] Efforts are underway at the National Renewable Energy Laboratory (NREL) and LBNL to develop better databases of saving shapes for EE and DR measures (https://www.nrel.gov/buildings/end-use-load-profiles.html). Those data sets are not yet available for our study.

more controls (occupancy sensors or variable speed drives) may be explicitly geared toward changing the end-use load shape. Furthermore we do not account for strategic DR which may change the end-use load shape, such as pre-cooling buildings to minimize AC loads on hot summer days, assessing the thermal storage opportunities of electric water heaters, or simple operational changes to dishwashers and clothes washers.

For this scoping study we leverage simulated end-use load profiles with hourly (8760) resolution. We draw our load shape data from two primary data sources. The first are National Renewable Energy Laboratory (NREL) simulations of building load components based on TMY3 weather data for many locations and building types across the United States. From this dataset we select lighting and geographically differentiated heating, ventilation, and air conditioning (HVAC) load shapes of residential and small commercial office buildings (Wilson 2014). In contrast to the HVAC load shapes, normalized lighting profiles from the NREL simulations were identical across multiple regions of the United States. Our second set of load shapes is the California Database of Energy Efficient Resources (CPUC 2011). From this dataset we select load shapes of residential dishwashers, laundry machines, and refrigerators from the Pacific Gas and Electric (PG&E) territory. As the usage of these appliances is fairly similar across the country we do not vary these shapes by region.

We normalize the load shape (and implied EE saving shape) data to equate 1 MWh of savings over the course of the year. This allows for a direct comparability in EE value across the country, even though the magnitude of the savings potential and the associated total costs of achieving this 1 MWh in EE savings may vary greatly across the country. We do not account for any potential changes in energy saving shapes between the year of EE data collection and our prospective year 2030 in which we evaluate the EE measures under different wholesale market conditions. Given the central role of these underlying load shapes in our analysis we recommend future research to evaluate a broader range of EE saving shapes that are geographically differentiated and that encompass more technologies, for example the recently developed energy conservation measures developed for the U.S. Department of Energy's Scout tool.[11]

Measure Description

Seven energy efficiency measures with different end-use load profiles were evaluated in each region. See Energy Efficiency for graphical representations of these measures and further details.

Large variations across regions were evident in the HVAC load shapes, driven in part by the relative cooling and heating contributions, as highlighted in Table 1. To represent the diversity of residential and small office HVAC measures throughout our regions of interest, we select two candidate cities for each ISO: Kansas City (Missouri) and Sioux Falls (South Dakota) for SPP, Buffalo and New York City for NYISO, Bakersfield and San Francisco for CAISO, and Dallas and El Paso for ERCOT. Residential HVAC profiles differed more in their diurnal shapes within and across regions: the load (on average across the year) peaks in the morning in San Francisco and in the afternoon in Bakersfield. The load profile is relatively flat in Buffalo but uneven in El Paso.

[11] Office of Energy Efficiency & Renewable Energy. Scout. https://www.energy.gov/eere/buildings/scout

In contrast, small office HVAC shapes that include both heating and cooling are more consistent across most cities (peaking in the morning with a second lower peak in the afternoon).

Table 1. Description of energy efficiency measures

Measure	Regional Variation	Characteristics
Commercial HVAC	2 cities per region	Tend to peak in the morning with a second lower peak in the afternoon; includes heating, cooling, and fan loads
Commercial Lighting	None	Morning ramp up followed by a relatively high plateau that gradually diminishes between 3pm and 9pm
Residential HVAC	2 cities per region	Variable profiles depending on region; predominantly cooling and fan loads (except Dallas that also includes electrical heating)
Residential Lighting	None	Small morning peak and large evening peak; low load during the middle of the day
Residential Refrigerator	None	Flat on average
Residential Clothes Washer	None	Late morning peak
Residential Dishwasher	None	Late evening peak with secondary late morning peak

Profiles for the other measures vary over the hours of the day, even if we assume that they do not vary by location. We see a clear complementarity in the end-use load shapes of small office lighting and residential lighting. Office lighting ramps up in the morning, followed by a relatively high plateau over the middle of the day that gradually diminishes between 3pm and 9pm. Residential lighting load, on the other hand, has a small peak in the morning and a large peak in the evening without substantial load during the middle of the day. Refrigerator load is rather flat; though warmer afternoon room temperatures lead to a small increase in load. Dishwashers are assumed to be used primarily in the evening (a small secondary peak exists in the late morning), while clothes washers have their highest load in the late morning.

Results

We focus on the combined energy and capacity value of EE measures in this discussion of results. First, we describe the direction, magnitude, and consistency of value changes of EE measures under different VRE penetrations. We then describe changes to the order of EE measures if ranked by their assessed value. Last, we discuss the relative impact of changes to the energy and capacity value of select EE measures.

EE Measure Sensitivity to Value Changes

Figure 5 shows that most EE measures see an overall reduction in their total electricity system value between the low VRE scenario and any of the three high VRE scenarios, driven primarily by the strong reduction in average wholesale energy prices with growing VRE penetration. For most measures and regions, this total value reduction is most pronounced in the high solar scenarios, which bring the greatest and most consistent change to diurnal price profiles, while the price effects of the high wind scenarios (where output between different wind projects is less correlated) are more irregular. The value changes in the balanced scenario usually fall between those in the wind and solar scenarios.

Large value changes

Across regions and high VRE scenarios, efficiency improvements to commercial lighting, commercial HVAC, and residential laundry machines see the greatest *reduction* in total value. In contrast, improvements to residential lighting *increase* in total value in ERCOT and SPP, retain their value in NYISO in the high solar scenario, and have the least value loss among all EE measures in CAISO.

Magnitude of value changes

The magnitude of the biggest value change depends very much on the ISO: While the value decrease is limited to \$10–\$15/MWh in SPP, it can increase to \$15–\$20/MWh in NYISO, \$15–\$25/MWh in ERCOT, and even \$20–\$25/MWh in CAISO. The value increase for residential lighting ranges from \$10/MWh in SPP to \$20/MWh in ERCOT.

Stability of EE value across scenarios

Not all EE measures experience a large change in their value in high VRE scenarios. In SPP, NYISO, and ERCOT improvements to dishwashers have a rather consistent value (without changes to user behavior such as active load shifting to low priced hours). More efficient refrigerators also perform similarly across low and high VRE scenarios, at least in SPP and ERCOT. In CAISO we observe very strong value reductions across all EE measures in the high VRE scenarios, without exception.

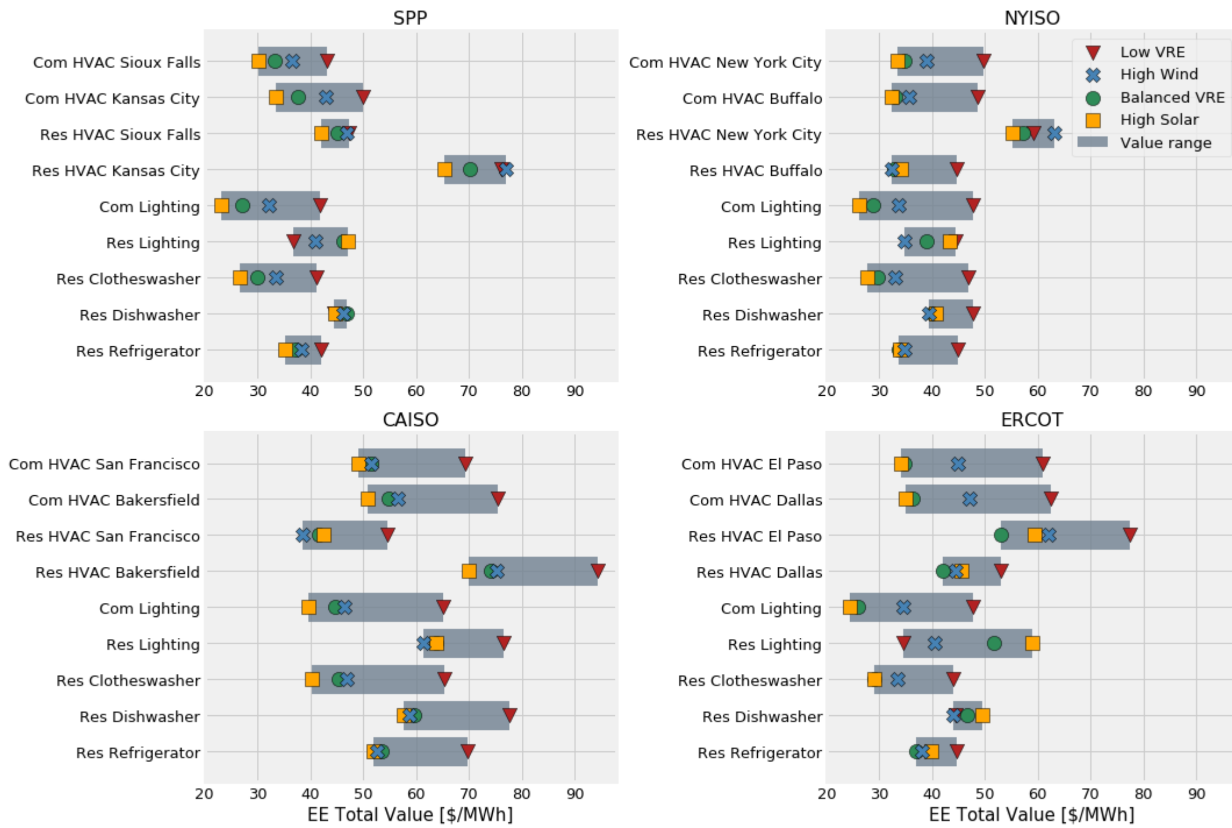


Figure 5. Combined energy and capacity value by EE measure across scenarios

EE Value order changes

While we only consider some value streams in our analysis and do not perform a full net-benefit study (i.e., including EE measure costs), a discussion about the relative performance of each measure compared to the other EE improvements is nevertheless useful. Across regions we find the impacts on the comparative value rankings to be the strongest in the high solar scenarios and the weakest in the high wind scenarios. As already indicated in the previous section that discussed the largest changes in absolute value, we find that small office lighting and HVAC measures have the strongest relative decline in value, as shown in Figure 6. While small office HVAC improvements rank among the highest value options in the low VRE scenarios in SPP, NYISO, and ERCOT (ranking 2–3 out of 9), they become less important in the high solar scenarios (ranking 6–7). Similarly, small office lighting, a measure with medium value in the low VRE scenario, falls to the least valuable option in the high solar scenarios in SPP, NYISO, and ERCOT. Residential lighting improvements in contrast ranks as the least-valuable measure in the low VRE scenario and transitions to one of the most valuable in the high solar scenarios in all regions.

High price spikes in the early evening in Texas in the high solar scenario also make reductions in dishwasher loads (via efficiency measures or changed user behavior) especially attractive. Interestingly, the relatively high solar penetration in our CAISO low VRE scenario (14 percent of annual energy) seems to already have affected the main value changes among EE measures. As a result, we do not see many further changes in the *relative ranking* of EE value as we increase solar penetrations further to 30 percent (though the absolute value continues to decline). However, very location-specific, residential HVAC improvements continue to score among the most valuable measures both in the low and high VRE scenarios across all regions. Residential HVAC efficiency improvements in a climate similar to that of Sioux Falls, South Dakota, is an example where relative directional change differs slightly between the high wind scenario (becoming more attractive) and the high solar scenario (becoming less attractive), though the absolute value does not change much between the two high VRE scenarios. Glancing over this exception, the directions of relative performance changes for all other measures is consistent in both the high wind and high solar scenarios

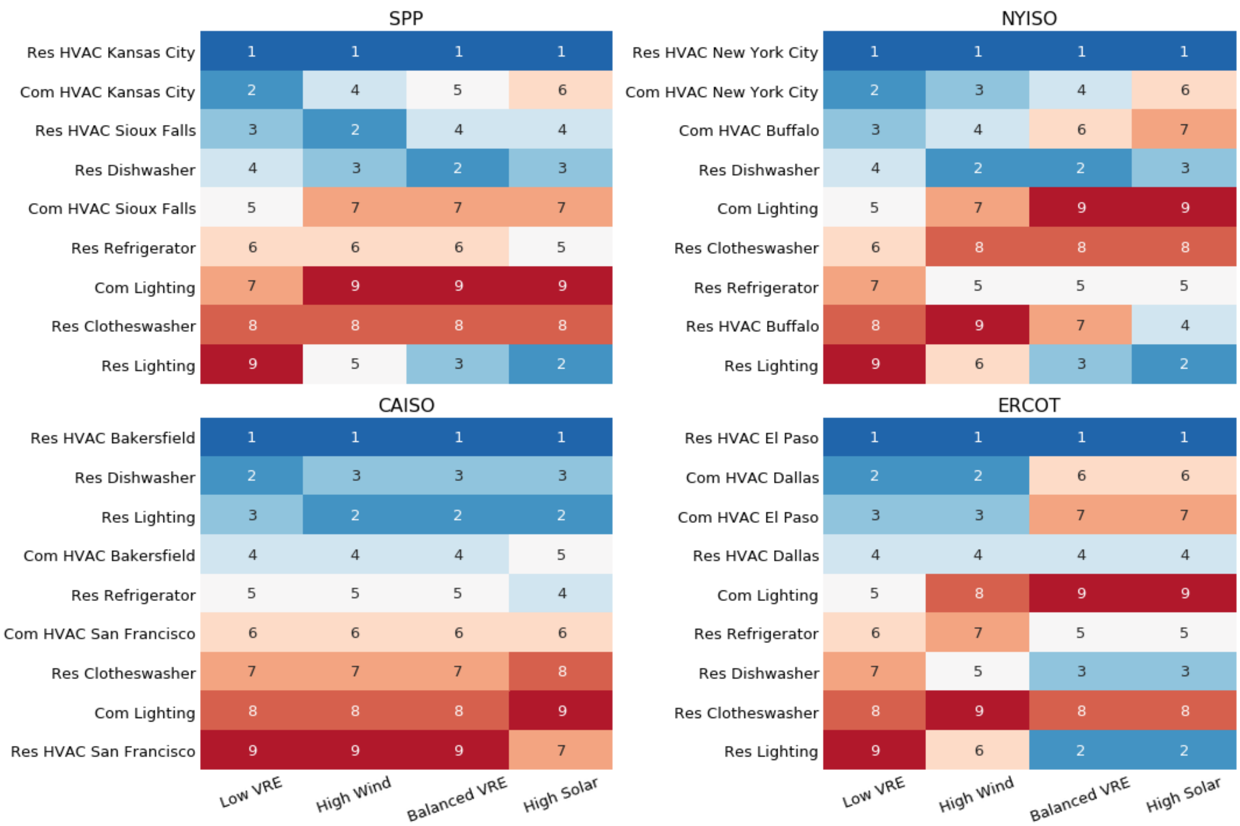


Figure 6. Relative ranking of EE measures by combined energy and capacity value

Figure 7 shows the changing order of EE measures by combined energy and capacity value from the low to the high wind and solar scenario in Texas. In addition to highlighting several of the trends already discussed, the overall "value curve" of energy efficiency measures seems to flatten in the high wind scenarios (meaning detailed value considerations become less important as the value differences become smaller), while the curve becomes slightly steeper in the high solar scenario. This suggests renewable resource-specific scenario analyses provide important information for a decision-maker choosing among different EE options.

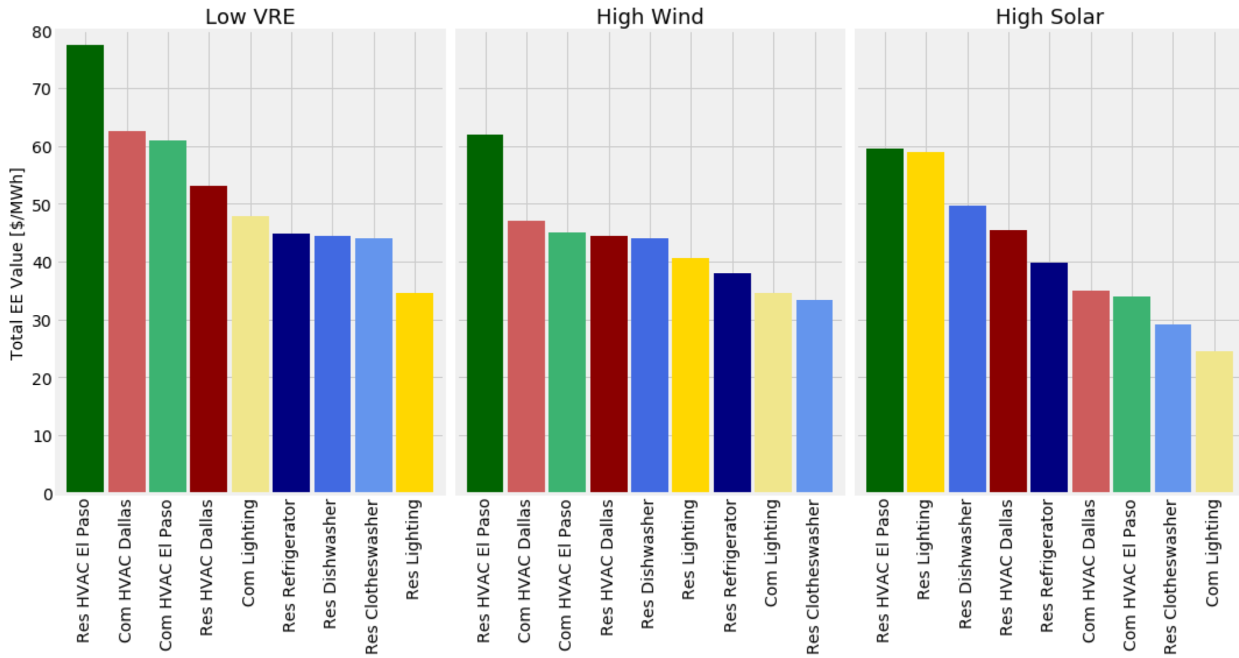


Figure 7. Relative order of energy efficiency measures in Texas

Intuition behind changes

The reduction in total value for most EE measures, and the change in the relative ordering among EE measures in the high VRE scenarios, can be explained by the shifts in wholesale electricity price patterns (both relative timing and total magnitude) brought on by increasing VRE penetrations. To explore the coincidence between hourly EE savings, energy prices, and changing top net-load hours, we examine in more detail three EE measures that have either positive, negative, or neutral total value swings.

Figure 8 shows how the energy value of dishwashers and residential and small office lighting improvements decrease across all regions and in most high VRE scenarios due to a general decrease in average energy prices caused by the merit-order effect of wind and solar.[12] As energy prices decrease, particularly during the middle of the day in the high solar scenarios, commercial lighting improvements that can reduce consumption during these hours fare especially poorly (see the load shape illustrated in Figure A-1 in Appendix A). In contrast, residential lighting improvements reduce load primarily in the early evening hours, when energy prices tend to spike in the high solar scenarios. Although the energy value is still reduced compared with the low VRE scenario, the relative value loss is the smallest.

The concurrence of load reduction with high net-load hours is shown by the capacity value of each EE measure. For dishwashers the loss in energy value can often be compensated by

[12] As wind turbines and photovoltaic (PV) systems have nearly no generation-dependent costs (such as fuel costs), they bid their generation at near zero costs into electricity markets—thereby shifting the merit-order curve (electricity suppliers ranked by their marginal production costs) to the right, which in turn lowers the clearing price for the respective bidding period.

increasing capacity value, so the total value change is modest. This is because capacity prices tend to increase in general at higher VRE penetrations in our modeling[13] and because top net-load hours shift from the early afternoon to the early evening. Residential lighting savings benefit extraordinarily from this change in the timing of the peak net-load, and as a consequence, the combined energy and capacity value even increases relative to the low VRE scenario in several regions. Small office lighting efficiency on the other hand loses out twice, facing general energy value reductions and capacity value erosions in the high VRE scenarios.

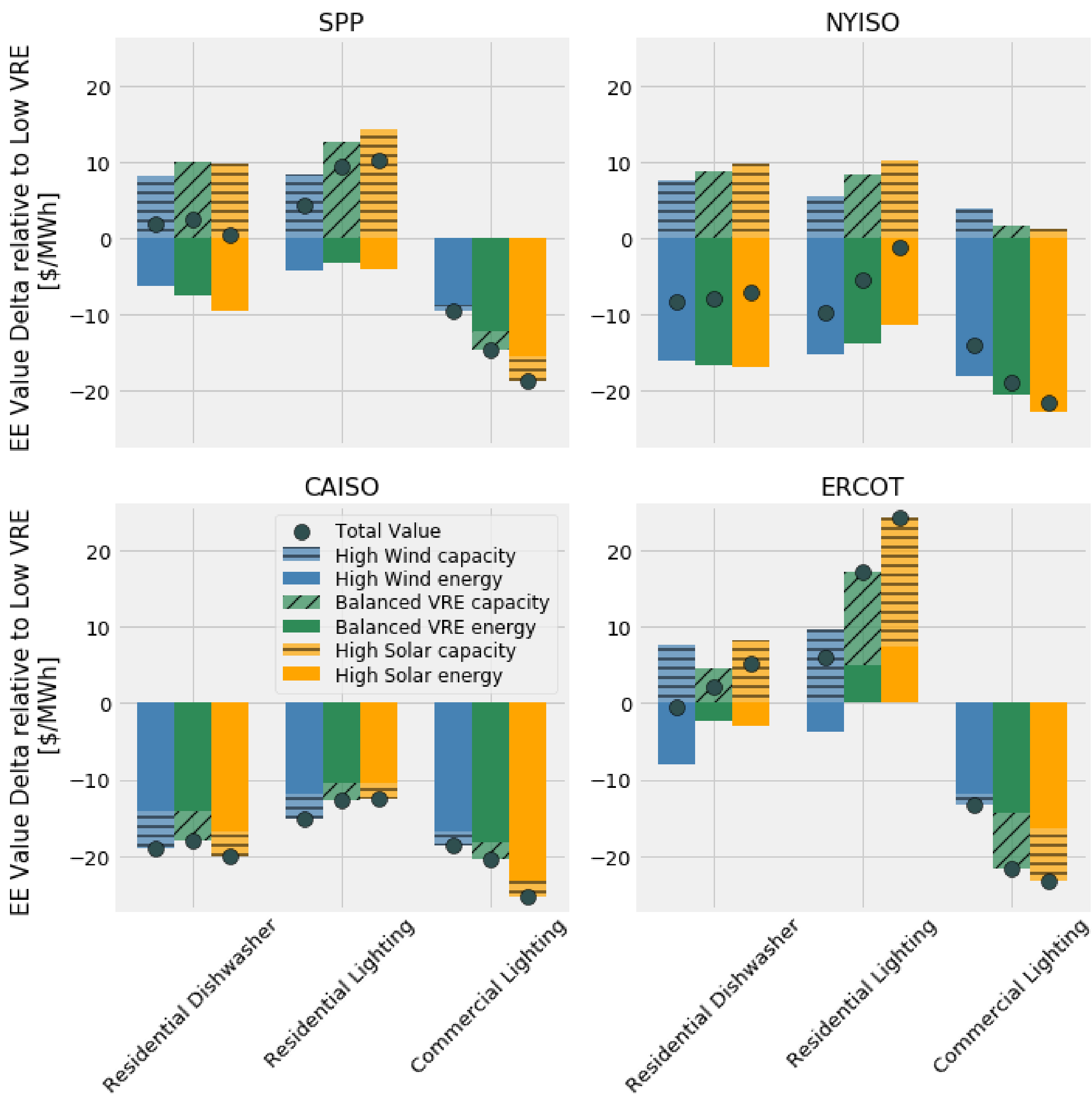


Figure 8. Directional changes in energy and capacity values of select EE measures

[13] Except in CAISO, where capacity prices decrease due to the retirement of inefficient generators in the high VRE scenarios that require revenue support in the low VRE scenario.

2.4 Discussion

We have shown that EE measure system value propositions can change decisively between a low and high VRE scenario—most often this means combined energy and capacity value decreases of 20 to 30 percent, but in select instances (i.e., residential lighting efficiency in Texas) the analyzed value can increase by a factor of two. These findings are relevant, as the general performance in cost-effectiveness tests is an essential aspect of the decision-making process of an EE program designer. Uneconomic measures that do not pass the total resource cost tests impact the cost effectiveness of the entire portfolio and are often excluded in EE programs across the country.

While our analysis has not included all the value streams that are usually considered (see Figure 4), our estimates of energy and capacity value changes are nevertheless important. Changes to the time-dependent transmission capacity deferral value are likely closely correlated with our estimated energy and generation capacity values, as transmission system needs are usually the highest at times of peak demand. Distribution capacity deferral values are similarly aligned, unless the net-demand patterns on the low voltage lines deviate much from total system net-load; for example, because of much higher or lower penetrations of distributed photovoltaics (PV) along the feeder, or high shares of PV systems that are coupled with onsite batteries. Non-energy benefits, and in particular avoided environmental externalities, can amount to large shares of the value proposition of EE measures (Myers and Skumatz 2006; Neme and Kushler 2010). However, the relative timing of these non-energy benefits is also likely closely related to our marginal energy cost estimates, as pollution effects and water consumption are largest at times of high demand and weak VRE generation.

Total cost-effectiveness of a measure rests, however, not only on the full value of energy efficiency, but also on the required investment costs that would unlock the EE value—an aspect that was beyond the purview of this scoping report. Especially investments to achieve the same amount of HVAC energy savings are very location dependent and will vary throughout the United States. Last, staff of a utility EE program will need to evaluate whether the market would indeed underinvest in particularly promising EE measures.

2.5 Conclusion

We have demonstrated the benefit that forward-looking scenario analyses leveraging time-dependent valuation approaches can offer to the EE decision-maker as they provide helpful information about resource trade-offs. While our set of exemplary EE measures was limited and relied on simulated load shapes, we illustrated that both the absolute values and relative ranking of EE measures will change with higher VRE penetrations. High wind scenarios can increase irregular hourly price volatility but can moderate average diurnal price profiles over longer periods—consequently, they may flatten the value differences between EE measures. In contrast, high solar scenarios have a strong effect on diurnal price profiles and can thus lead to stronger value differences between EE measures, making the conscious choice of appropriate EE measures even more important and highlighting the advantage of VRE-specific scenario analyses. Residential EE upgrades that lower consumption in the evening seem to become more valuable than office EE upgrades that provide savings during the day in delivering high value savings, and those residential EE upgrades could be targeted in future program design.

Future research can build on this knowledge by evaluating a broader set of EE measures (e.g., electric space and water heaters) and leverage more robust empirical and location-specific EE saving shape data. Our appraisal included only static EE savings shapes and did not consider interactions of EE and active load management that can maximize value by shifting load from high to low price periods (e.g., clothes washers and dishwashers with more advanced controls)—an ability set that will become increasingly important in an environment with more variable prices (Alstone et al. 2016). We recommend expanding the scenario analysis to assess the implications of different EE uptake scenarios and include additional value streams, such as location-specific T&D capacity values, as they may lead to the strongest deviation from our value rankings. Detailed cost-effectiveness studies will of course need to consider measure costs.

Given the longevity of EE upgrades, decision-makers might consider the implications of more dynamic price patterns brought on by VRE to avert investments that may offer little system value in a few years, or avoid under-investments of measures that are likely to provide respite at times of high system needs.

3 Opportunities for Large Energy Consumers

3.1 Introduction

Industrial energy use in the United States from manufacturing, agriculture, construction, forestry and mining is primarily from on-site consumption of natural gas (59 percent and coal (7 percent) with electricity providing only 31 percent of the energy (U.S. Energy Information Administration (EIA) 2014). The fuels are primarily burned to generate process heat. But electricity can also be used directly for heat production using electric boilers, large-scale electric heat pumps, resistance heating, microwaves, induction, and electric arc furnaces (Sandalow et al. 2019). A more indirect fuel substitution may involve first making "bridge- or electro-fuels," such as hydrogen, synthetic fuels, and other derivatives, which are then burned in industrial processes (Friedmann, Fan, and Ke 2019). More generally, electricity can be used to make a range of conventional products, commonly referred to as power-to-X, which can then be processed for a variety of chemical and energy applications, including for example ammonia for fertilizers (International Energy Agency 2019; Philibert 2017).

For large energy consumers, the availability and price of energy is a significant factor in decisions about capital investments, operations, and siting. Based on our previous modeling, fundamental price characteristics of the wholesale power system change with high shares of VRE. In particular, high VRE scenarios increase the frequency of periods with the low wholesale electricity prices associated with high VRE generation levels. For example, our modeling of a high solar scenario in ERCOT indicates that nearly 20 percent of all hours of the year, especially during the middle of the day, may have wholesale electricity prices lower than $5/MWh. This section explores whether long-lasting investment decisions by large energy users—using energy in both current and emerging applications—would differ in high VRE scenarios relative to decisions with low VRE.

Periods of low-priced electricity in the wholesale market could present a sizeable opportunity for large energy consumers to reduce costs, assuming they have access to wholesale electricity markets or that their retail prices reflect overall wholesale price dynamics. Increasing availability of periods of very cheap electricity can motivate industrial energy users to invest in equipment that allows flexibility to switch from direct fossil fuel consumption to electricity during these low price periods, to modify their production processes,[14] or to use electricity to make products that compete with those derived from fossil fuels or other natural resources, such as hydrogen from electrolysis.

These decisions would be based on a variety of factors, but primarily on how capital investments and operating expenses would affect the per-unit cost of their products. For energy-intensive applications, where electricity is a significant operating expense, a high VRE scenario could offer

[14] Opportunities for increased flexibility in electricity consumption also include refrigerated warehouses that can be operated within an acceptable temperature band and that can be thus pre-cooled when electricity is cheap (Alstone et al. 2016). Likewise water pumping for crop irrigation can account for sizable loads in rural areas that could be shifted, within limits, to coincide with periods of lower-priced wholesale electricity, as some utilities have already demonstrated (Nebraska Public Power District 2018; 2018).

a reduction of per-unit costs. Furthermore, targeted research and development on advanced manufacturing processes could identify innovative ways for large energy consumers to reduce costs by increasing their flexibility in order to take advantage of low prices.

To identify which kinds of end-user decisions might be sensitive to VRE scenarios, we first identify a set of factors that would influence such decisions, such as technical, economic, and market factors. We then discuss promising opportunities for flexible energy consumers and choose three end uses to illustrate how different aspects of long-lasting investment decisions might change in a high VRE scenario relative to a low VRE scenario. To develop case studies for these applications and decisions, we create simplified models of their energy demand, assume some plausible technical and operational changes, and evaluate the economic performance in low and high VRE environments.

The results of this scoping study should be considered primarily as a way to explore how end user decisions may change in response to changing price dynamics with high VRE scenarios, and not as an authoritative assessment of economic or technical potential. A detailed engineering analysis would be required for each application that would likely involve more sophisticated modeling approaches and a fuller accounting of costs and benefits to assess their respective potential.

3.2 Qualitative Summary of the Decision-Making Process

Decision Factors

Wholesale electricity price dynamics are likely to be considerably different with high levels of wind and solar than they would be in a low VRE scenario, potentially prompting changes in capital investment choices or energy usage behavior from many large energy users. In assessing end-use applications for the present study, we look for technical and economic characteristics that could allow large energy users to take advantage of new price dynamics in a high VRE world.

Some end users will be better able than other users to respond to prices under high VRE scenarios, and could be driven to make different decisions than they would under low VRE scenarios. The best candidates are those with the following characteristics:

- **Energy intensity:** Energy makes up a significant portion of the customer's operating costs, such as with energy-intensive industries like chemical and metals manufacturing. Customers with high energy costs will be more motivated to change behavior to seek lower costs.
- **Technical flexibility:** Users can change their operations and locations in response to more highly variable price dynamics. This could mean, for example, that they could curtail or increase operations for certain times of day or seasons while still delivering their product as needed. Users that produce energy-intensive end products that can be stored at low cost—including for example metals, purified water, or heat—can often have greater flexibility. As a result these users may choose to locate their operations strategically near electricity pricing nodes with favorable price dynamics.

- **Financial flexibility:** Users with energy costs making up a large fraction of levelized product costs have relatively lower capital costs. Those lower capital costs provide flexibility in making capital investment decisions, and allow users to curtail operations profitably. Conversely, higher capital costs put a premium on high utilization rates, or "baseload" operation, of the capital equipment, making users less likely to change in response to energy prices. This financial flexibility could guide whether an industrial customer chooses a natural gas boiler, an electric boiler, or a high efficiency electric heat pump, for example.
- **Favorable returns:** Investments made to increase flexibility and capture lower-cost energy supplies have to be cost effective, with enough value and scale to justify the change in operations. Using electricity to produce hydrogen for a specific chemical production process, for example, may be a high value but small market opportunity, while converting electricity to heat may be the opposite.
- **Environmental motivations:** A growing number of corporations are motivated to reduce carbon emissions due to regulations, consumer demand, or their own corporate goals. Switching from fossil energy to zero-carbon VRE can be an attractive way to cut emissions, especially if it is sufficiently low cost.

Characterizing Opportunities

Large-scale energy use is diverse in its form and so are the potential applications for periods of low-priced wholesale electricity. Rather than attempt to evaluate opportunities for all potential industrial applications, we instead showcase different aspects of technical and financial flexibility considerations with three case-studies focused on high energy intensity consumers.

First, we use the example of hydrogen production by electrolysis to discuss the impact of fixed capital and variable operational expenses on levelized production costs in the context of varying electricity price dynamics of low and higher shares of VRE. We show how cost-minimizing utilization rates change with VRE scenario. Because the general framework in this case-study can be applied to other electro-commodity production processes, we then abstract from hydrogen production to assess how longer continuous run-time requirements or different capital cost and efficiency characteristics may affect the decision to produce a generic electro-commodity. Finally, we examine the effect on VRE scenarios on the pay-off of R&D investments that either reduce Capex requirements or increase process efficiency.

The second case study extends the electro-commodity discussion to evaluate opportunities to decouple the timing of demand and production through investments in increased product storage. We use the example of desalination operations that could add fresh water storage at relatively low cost to allow for more variable operations while continuing to meet community needs for water. Our case study assesses a large brackish groundwater desalination plant in El Paso, Texas across different VRE penetration scenarios.

Our final example weighs gains from investments that enable energy source flexibility against increased upfront capital costs. We use the example of district energy systems that can incorporate electric heating and cooling into a hybrid fossil fuel/electric system. We gauge whether electricity prices in a high VRE scenario are low enough to justify investments that enable dynamic switching between fuels based on relative energy prices. Our case study examines simplified DE systems at college campuses across the United States.

3.3 Quantitative Analysis of Opportunities for Large Energy Consumers under High VRE Penetrations

The following section describes a framework for examining how decisions made by industrial operators could change in VRE scenarios. We first describe our general analytical approach—the evaluation of levelized unit costs across different VRE penetration scenarios—and then test the three long-lasting investment decisions by looking at potential impacts of changing electricity price dynamics in the three case studies. For each application we begin by detailing our process assumptions and then describe our main findings. Where applicable we discuss how our results can be generalized to other industrial applications.

Analytical Approach

Our analysis evaluates the levelized cost of three different commodities (hydrogen, water, heat) under the four different VRE penetration scenarios described in this report's introduction. The four VRE scenarios featured a low VRE scenario and three high VRE scenarios ranging in penetration levels of wind and solar generation.

Throughout each of the three investment decisions, our impact test is how levelized per-unit costs change for the commodity production process at hand. Our cost calculation includes capital costs, maintenance costs, operating costs, and the annual production volume of the commodity. We selected capital expenditure (CapEx) estimates based on literature reviews, and maintenance costs are determined as a percentage of total capital costs. Operating expenditures (OpEx) are a function of the monthly fuel or hourly electricity price, the efficiency of the technology in converting the fuel input into the commodity, and how many hours per year the technology operates. For flexible production processes we minimize operating expenditures by operating during hours with the lowest available electricity prices (assuming perfect price forecasts). Because production occurs in lowest priced hours first, increasing the hours of production leads to a general rise of the average coincident electricity prices.

As explained above, levelized per-unit costs are expressed as a function of capital costs, maintenance costs, and operating costs. Capital and maintenance costs are calculated on a per-year basis, while operating costs and unit production are calculated hourly.

$$Levelized\ Cost\ \left(\frac{\$}{Unit}\right) = \frac{Annual\ CapEx + Annual\ Maintenance + \sum_{h=1}^{8,760} OpEx_h}{\sum_{h=1}^{8,760} Quantity\ of\ Product_h}$$

We calculate hourly operating costs by multiplying the hourly energy price by the amount of energy required to produce one unit (a measure of efficiency or energy intensity) and the number of units produced in that hour. We primarily focus on electric energy consumption, but also evaluate natural gas use and time-varying natural gas prices in the district energy example. Annual operating expenses equal the sum of hourly operating expenses.

$$OpEx_h(\$) = \left[\frac{Energy\ Cost}{MWh}\right]_h * \frac{MWh}{Unit\ of\ Product} * Quantity\ of\ Product_h$$

We obtain annual capital costs from total capital costs using the standard capital recovery factor, where *N* represents the amortization period in years, which is assumed to be less than the project design life in many instances. We account for financing costs of the upfront capital expenditure through a discount rate.

$$Annual\ CapEx\ (\$) = Total\ CapEx * \frac{Discount\ rate}{1-(1+Discount\ rate)^{-N}}$$

This analytical framework is general enough to specify different cost assumptions and apply them toward other electricity-intensive commodities that are not covered here.

Limitations

An important limitation of our approach is that we assume industrial end-use customers pay only wholesale energy and capacity costs, as illustrated in Figure 9. While our market modeling includes the wholesale price effects of an expanded transmission system to integrate new wind and solar resources, we do not incorporate the costs for either the legacy or expanded transmission system explicitly in our value analysis of new industrial end uses; for example, via transmission cost tariff adders. Similarly we assess changes in reserve requirements due to higher VRE penetrations but do not examine the value or costs that the strategic operation of new industrial end uses may have on ancillary services. We do not evaluate specifically how the deliberate use of flexible loads may facilitate overall integration efforts of variable renewables or how they may reduce overall system costs at very high shares of wind and solar penetrations. Furthermore we do not include a full social accounting of environmental costs, retail rate riders, or special retail tariff price signals in our analysis distribution costs. On the other hand we only leverage ISO-wide average prices and do not evaluate the opportunities on a nodal basis, where LMPs show an even higher level of price fluctuations or periods with even negative electricity prices that may be even more attractive for flexible industrial energy users.

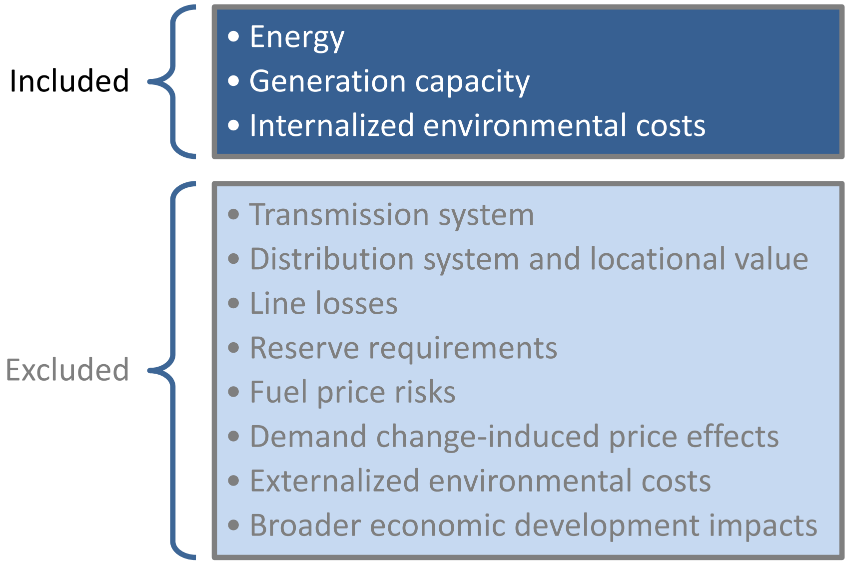


Figure 9. Included electricity cost components in the emerging application analysis

We also do not perform a full engineering cost and feasibility analysis, but rather create simplified models that trade-off between CapEx and OpEx, with OpEx being the price of electricity. A more thorough analysis would be needed before committing to significant investments, evaluating potential further retrofit costs and changes in system performance. Due to these limitations, we emphasize directional changes in unit costs rather than the absolute magnitude of the costs we estimate. While there is interest in projections of specific changes in unit costs (e.g., future hydrogen production costs), the focus of this scoping report is how the relative cost of different production processes may shift based on changing wholesale electricity price dynamics in a scenario with low or high levels of variable wind and solar energy resources.

Hydrogen Production and Other New Electro-Commodities

The first decision we assess is the production of commodities that are currently not produced on a large scale with electricity as primary energy source. This decision asks the industrial end user if changes in wholesale electricity generation and capacity prices now make it viable to open a new plant or production process that primarily uses electricity to manufacture a commodity. These electro-commodities may range from hydrogen production to synthetic fuels, metals refining, or carbon fiber production. We first discuss production of hydrogen via electrolysis, which is an electricity-intensive process that runs an electrical current through water to separate hydrogen and oxygen. We later abstract from hydrogen production specifically and show how electro-commodity production processes with longer continuous run-time requirements or different capital cost and efficiency characteristics may affect the decision to produce a generic electro-commodity.

Assumptions

We model an alkaline electrolyzer within each of the four ISO market regions operating at 70 percent process efficiency (de Bucy 2016; Nagasawa et al. 2019).[15] As described in the analytical approach section above, we assume a highly flexible operation of the electrolyzer without an obligation to deliver a predetermined quantity of hydrogen—instead the number of operating hours and resulting product quantity are chosen with the objective of minimizing the overall levelized production costs. As such the electrolyzer starts to operate during the hour with the lowest available electricity price and gradually ramps up production until the marginal rise in electricity prices leads to an overall increase in levelized production costs (highlighted later in Figure 11).

We incorporate key assumptions of NREL's "H2A: Hydrogen Analysis Production Case Studies"[16] and assume "uninstalled costs" of $400 per kilowatt (kW) of electrolyzer capacity, equivalent to $650 per kW once we account for additional costs such as permitting, fees, and project contingencies. These estimates incorporate future anticipated technological improvements and are more competitive than currently available commercial prices (de Bucy 2016; International Energy Agency 2019; Saur and Ainscough 2011; Wood Mackenzie 2019). To highlight the effects of varying capital costs we run additional sensitivity scenarios of "uninstalled electrolyzer costs" of $900/kW (similar to current costs), and aggressive cost targets of $200/kW and $100/kW.[17] The sensitivity results are detailed in Figure B-1 through Figure B-3 in Appendix B.

We assume replacement of the electrolyzer cell stack after 60,000 hours of operation at a cost of 25 percent of the total capital expense (de Bucy 2016). Maintenance costs are estimated at 4 percent of the capital expense. The lifetime of the electrolyzer is assumed to be 25 years with an amortization period of 10 years and a discount rate of 6 percent. We assume that the alkaline electrolyzer is highly flexible, with startup times of less than an hour (in contrast to the later discussion of longer minimum run times resulting in batch constraints).[18]

Lastly, we model only the production costs of power-to-H_2. Additional costs include compressing the gas and distributing it to retail stations for use in vehicles, to pipelines for blending with the natural gas supply, or to other industrial customers for use in ammonia or synthetic natural gas production. Because our assessment focuses primarily on how the generic decision to produce an electricity-intensive commodity changes between VRE penetration scenarios, we exclude the nuances of modeling the hydrogen distribution network, as those cost components will vary less between scenarios.

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[15] Also see NREL's H2A: Hydrogen Analysis Production Case Studies. https://www.nrel.gov/hydrogen/h2a-production-case-studies.html

[16] NREL. H2A: Hydrogen Analysis Production Case Studies.

[17] The cost estimates are derived from NREL's current and future central hydrogen production models for polymer electrolyte membrane (PEM) electrolysis (Saur et al. 2018a; 2018b).

[18] In our review of electrolyzer technologies, we found alkaline electrolyzers can start within 45 minutes from a cold start and within a few minutes from a hot start.

Hydrogen Production Findings

First, due to high energy demands of H_2 production and greater availability of low-priced electricity, we find that the levelized cost of hydrogen production decreases in high VRE scenarios by 13 to 40 percent. Figure 10 demonstrates that operating expenses represent the largest contribution to levelized cost in H_2 production, and that indeed production costs decrease with greater penetration levels of VRE and associated lower electricity prices. High solar scenarios, which feature the greatest share of hours with very low electricity prices, also offer the lowest overall production costs. Although the trend in scenarios is consistent across each ISO region, we find that wholesale prices in ERCOT, SPP, and NYISO enable producing hydrogen at less than $2/kg (or even below $1/kg if substantial electrolyzer CapEx targets of $200/kW or even $100/kW are achieved, see Figure B-2 and Figure B-3 in Appendix B). Carbon prices in CAISO and NYISO increase our modeled electricity prices and contribute to higher hydrogen production costs.

A second related result from this assessment is the change in the contribution of cost factors to total levelized cost in low versus high VRE scenarios. Both the decrease in levelized operational costs and a reduction in optimal electrolyzer *utilization rates* (the annual share of hours during which the electrolyzer operates) lead to an increase in the relative weight of capital costs in a high VRE scenario. Figure 10 plots the share of capital, maintenance, and operating costs for each ISO and VRE scenario. Most noticeably in CAISO, which features the lowest electrolyzer utilization rates as described below, capital expenses constitute a much larger share of total levelized cost than they do in the low VRE scenario. Lower capital costs enable plant operators to run the electrolyzer only during the lowest cost hours, which in turn further decreases the OpEx share of total levelized costs and makes capital costs the dominant production cost driver (see Figure B-5 and Figure B-6 in Appendix B).

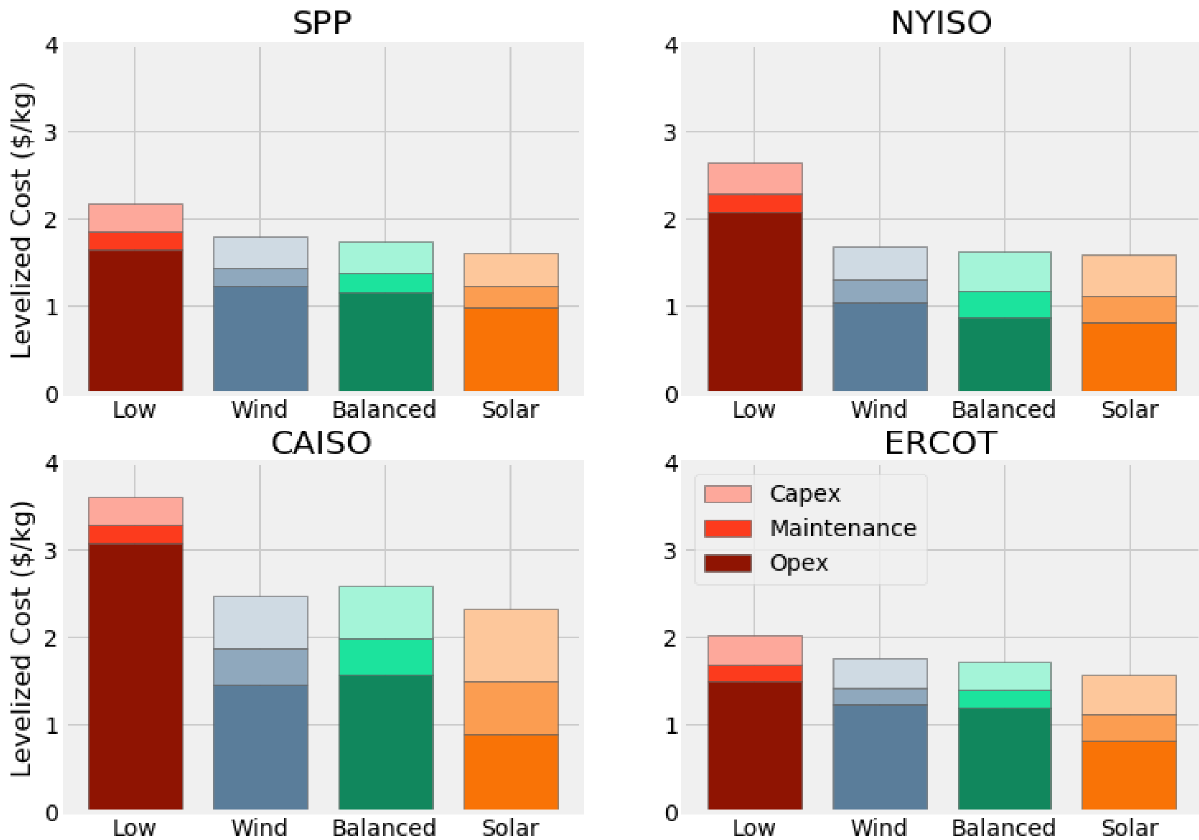

Figure 10. Levelized hydrogen production costs by component across scenarios

It may be counterintuitive to find lower optimal utilization rates, i.e., those that decrease levelized production costs the most, with increasing renewable penetrations that feature generally lower average electricity prices. The primary rationale is that in high VRE scenarios, a plant operator can recover the bulk of the capital expenditure during hours with near-zero electricity costs. The operator is then less motivated to continue to produce, as electricity prices increase above those low price levels. In contrast, the scenario with little VRE penetration does not present a similar opportunity to recover all the upfront capital expenditure during only low-priced hours. As a result, the plant operator recovers the capital expenditure only over more hours at the middle of the price duration curve, where electricity prices are generally flatter. Because prices are flatter, the operator may then choose to utilize the equipment more and further reduce per-unit capital costs. In contrast, the high VRE scenario features a steeper price distribution, so the operator is less motivated to continue ramping production volume (Seel, Mills, and Wiser 2018). The selective use of production equipment (especially in the high solar scenarios) may necessitate investments in product storage to enable continuous supply for customers. We will discuss such considerations in the context of water storage for a desalination plant in section 3.3.3.

Figure 11 shows utilization rates in the low VRE scenario range from 75 to 82 percent compared to 27 to 82 percent in the high VRE scenarios (even going down to 10 percent under very favorable CapEx of $100/kW assumptions, see Figure B-6 in Appendix B). The vertical dashed lines intersect the levelized-cost curves at their respective minimums. Despite the variation in utilization rates, the levelized-cost curves are mostly flat after utilization of 3,000 hours per year, except for the last hours, with the highest electricity prices that lead to an uptick in levelized costs. Other operational concerns, like maintaining regular hours of employment for staff, might offset the (minor) production cost savings. This trade-off changes, however, if strong capital cost reductions are achieved, as the cost slope becomes steeper, and increasing electrolyzer utilization from 1000 hours to 8000 hours can lead to an increase in levelized production costs of more than $1/kg of hydrogen (see an example of the high solar case in CAISO in Figure B-6 in Appendix B).

Utilization rates also vary between ISO regions. ERCOT, a region with a rather flat price duration curve for most of the year, has utilization rates that are almost double the rates of a hydrogen electrolyzer in CAISO, a region with a much steeper price duration curve in the high VRE scenarios (Seel, Mills, and Wiser 2018).

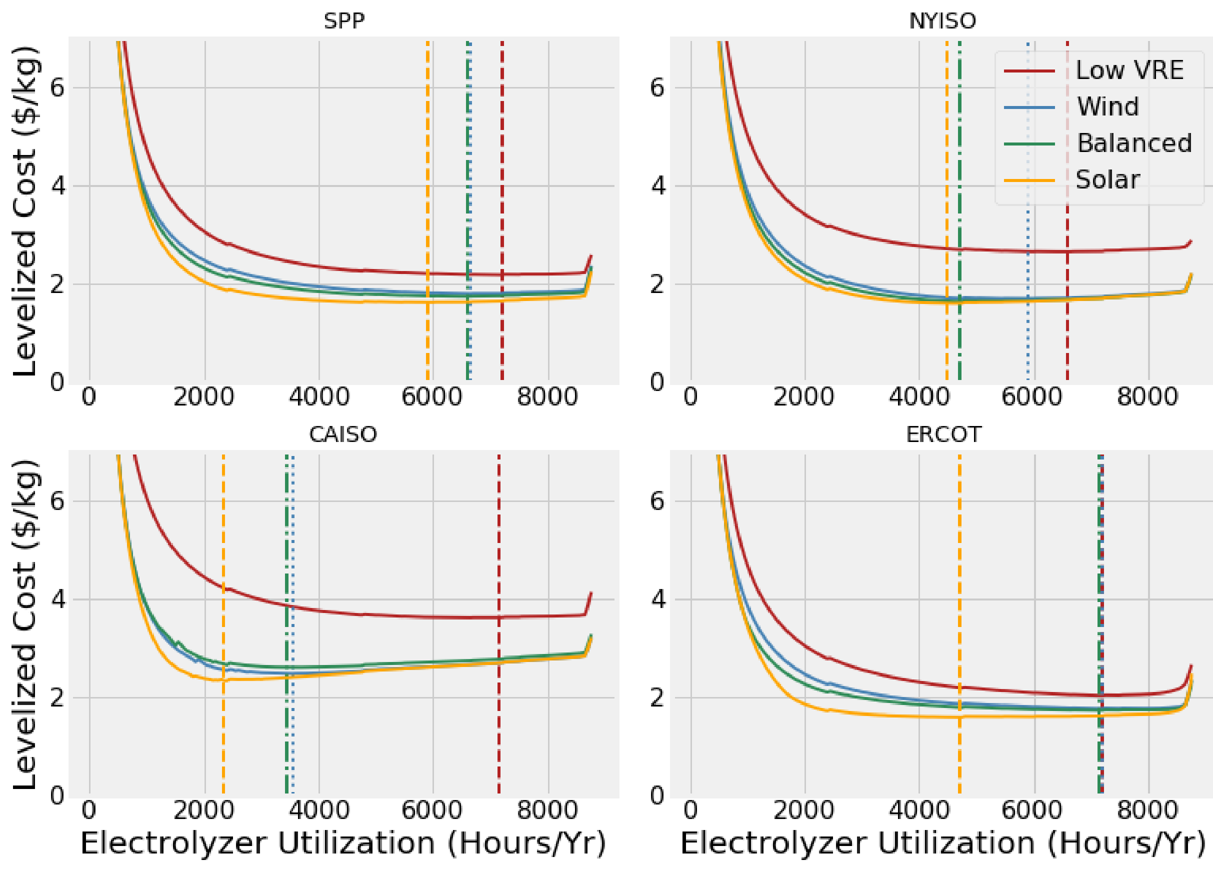

Figure 11. Cost minimizing utilization rates of the electrolyzer across scenarios

Implications of Production Batch Constraints of Other Electro-Commodities

The hydrogen production examined above is a very flexible production process with negligible runtime constraints. We now assess how technology constraints of other electro-commodities (for example other synthetic fuels, metal refining, or carbon fiber production, which require longer production runtimes [Sandalow et al. 2019]) affect our findings. Some manufacturing technologies may be extremely flexible, featuring quick start-up and shut-down times, while other processes may have a slower response time and cannot take advantage of spurts of very low electricity prices as easily. An example of a less flexible process are steel mills that use direct electrolysis and that may not be able to interrupt a batch of steel if prices rise. Hence, we include a constraint that minimum run times may need to be at least 2 hours up to at least 24 hours, and compare their production costs with the no-constraint base case. Figure 12 shows that longer batch requirements indeed raise the levelized cost by several percentage points, and at most 15 percentage points in the case of CAISO.

Cost increases are also stronger in high solar scenarios when prices vary more over time periods shorter than eight hours and longer batch processes benefit therefore less from short spells of low prices. Higher wind penetrations in ERCOT on the other hand can smooth regular diurnal price variability over 12 to 24 hour periods (see the fourth row in Figure 2), leading to less cost increases relative to the low VRE scenario. Depending on relative capital cost and efficiency assumptions, these production cost increases are, however, usually lower than the cost savings offered by lower electricity prices in the high VRE scenarios.

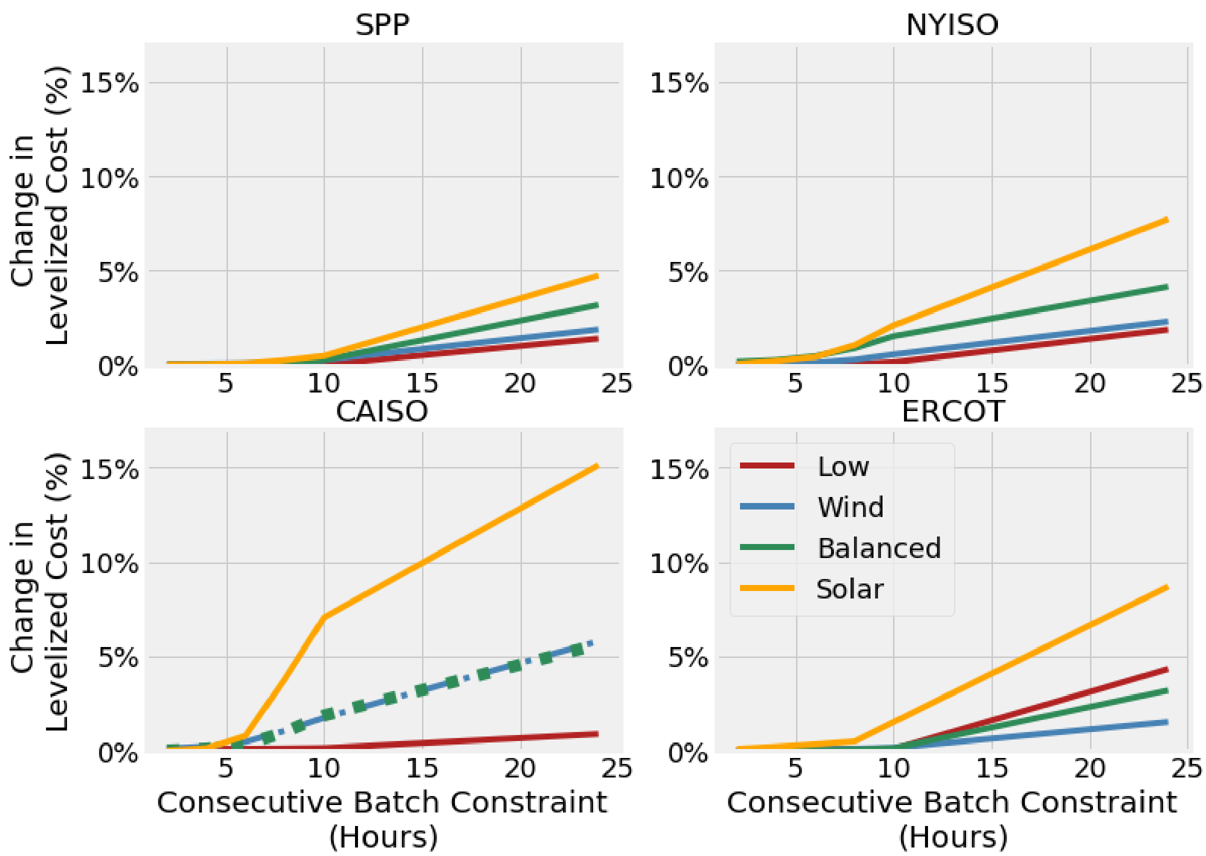

Figure 12. Impact of batch constraints on levelized costs of electro-commodities across scenarios[19]

[19] The 10-hour constraint in ERCOT in the high solar future did not produce a solution. The change in levelized-cost curve for ERCOT in the high solar future is therefore interpolated between 8 hours and 24 hours.

We also find that longer batch constraints result in a greater number of operating hours per year. Figure 13 contrasts the cost-optimal number of operating hours per year and associated levelized costs of a production process that is either unconstrained or that must operate continuously for 24 hours. The 24-hour constraint shifts the levelized-cost curve up, leading to an increase in production costs. At the same time the cost curve flattens, and this more gradual slope results in a higher optimal utilization rate.

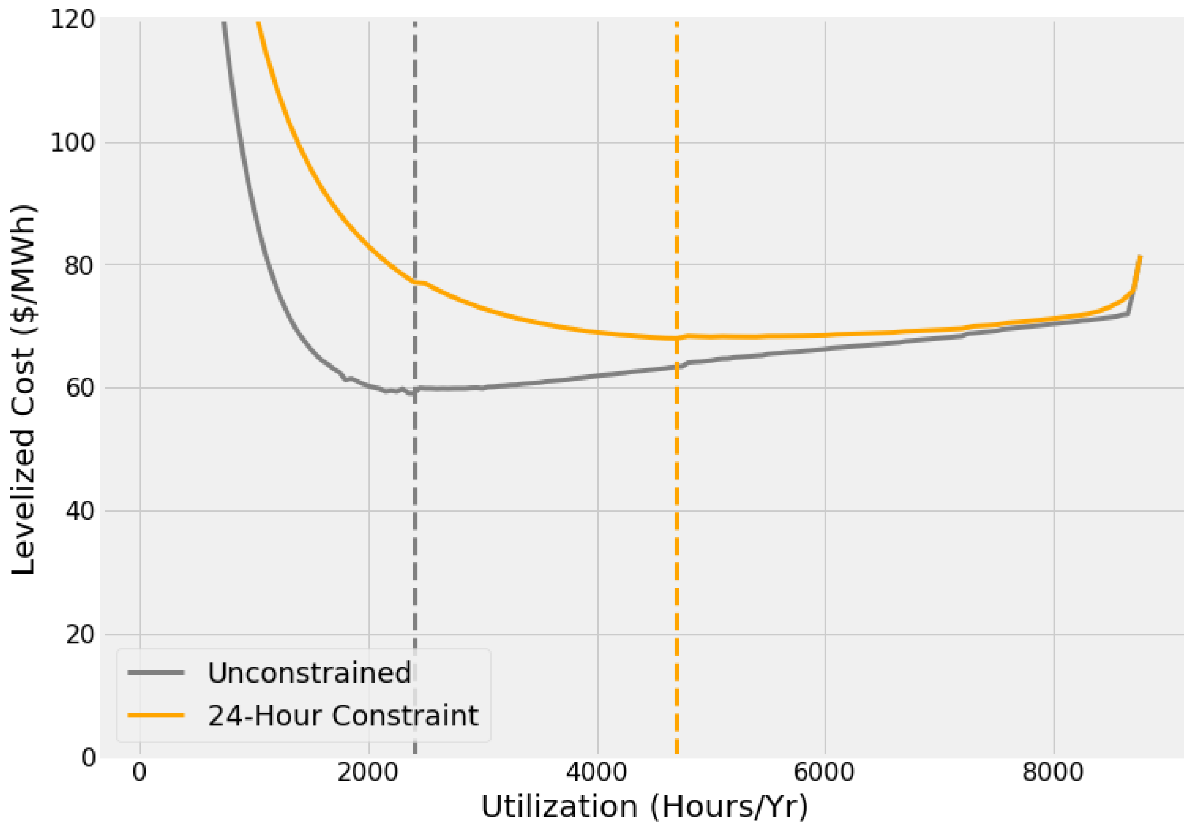

Figure 13. Impact of batch constraints on utilization rates of electro-commodity production in the CAISO high solar scenario

Impacts of Cost and Efficiency Improvements of Electro-Commodities

We now abstract even further and model the levelized cost of a generic electro-commodity as a function of capital cost and process efficiency, to assess how variations in each parameter impact the relative opportunities of benefitting from low priced electricity periods in a high VRE scenario. To facilitate the comparison we only present our low VRE scenario and a single average of our three high VRE scenarios. Figure 14 plots levelized cost on the vertical axis as it varies with installed capital cost on the horizontal axis. As discussed above, each combination of capital costs, efficiency, and wholesale price assumptions yields a specific optimal process utilization rate, and the figure only plots those lowest levelized costs for a given capital cost. Hypothetical variations in process efficiency are depicted by the area charts: The lower bounds represent a highly efficient process (90 percent) enabling generally lower costs, while the upper bounds showcase a less efficient process (50 percent) with higher associated costs. The levelized costs are expressed in generic dollars per megawatt-hour of energy output; these numbers can be converted to commodity-specific production costs using the relative energy intensiveness of the specific commodity.

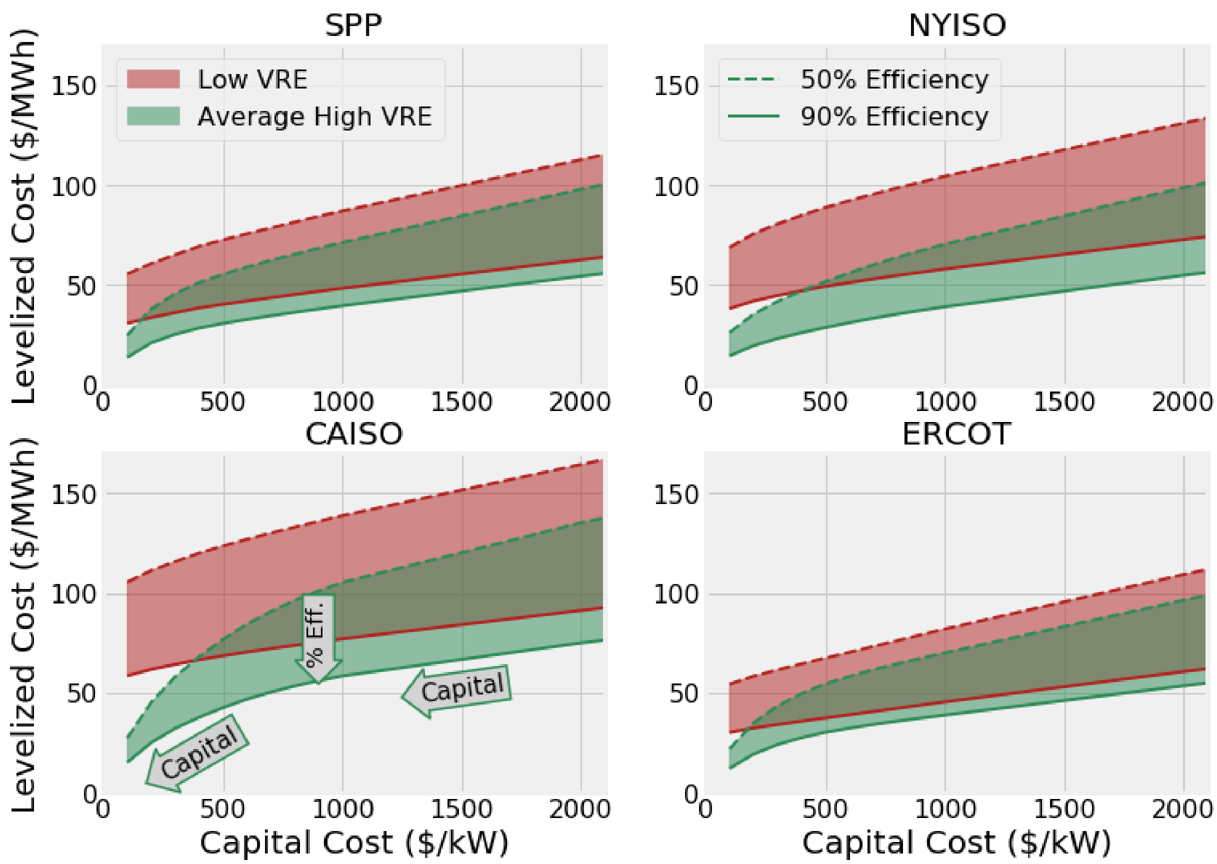

Figure 14. Levelized costs of an electro-commodity as a function of capital costs and process efficiencies across scenarios

Commodities with high capital costs (representing the dominant share of all-in product costs, on the right end of the plot) will not see a significant difference in levelized cost between low and high VRE scenarios. The decision whether to produce such commodities will consequently *not* substantially hinge on the potential pathway of VRE penetration levels. In contrast, commodities with lower capital cost shares (on the left end of the plot) and higher operational cost shares diverge strongly in levelized cost in low versus high VRE scenarios. These findings are also illustrated well by looking at the relative cost savings of our hydrogen cost sensitivities. At high CapEx assumptions of $1500/kW (fully burdened) the VRE cost reduction opportunities are modest (Figure B-1 in Appendix B), while costs can decline by a factor of more than three under low CapEx assumptions of $165/kW (Figure B-3 in Appendix B).

Furthermore, the shapes of the area charts change at low capital costs: The steeper slopes of the high VRE area chart imply that an improvement in capital costs yields a larger cost reduction in the high VRE scenario. In the scenario with lower VRE penetrations and higher average electricity prices, capital cost improvements in contrast result in fewer savings.

Going back to our hydrogen production example with fully burdened capital costs of $650 per kilowatt, we find a 10 percent capital cost improvement to $585/kW enables production cost savings of only 1.5 percent in the low VRE scenario in CAISO but 6.2 percent in the high solar scenario in CAISO (or 5 cents/kg versus 14 ¢/kg, respectively, in absolute terms).

In contrast, a 10 percent improvement in process efficiency from 70 percent to 77 percent results in equivalent production cost savings of 9.1 percent in both the low and high VRE scenarios. As overall electricity prices decline with growing VRE shares, the savings actually decrease in absolute terms from 33 ¢/kg in the low VRE scenario to only 21 ¢/kg in the high solar scenario in CAISO. With lower capital cost starting points (e.g., $165 instead of $650), the decreased cost savings from efficiency improvements in high VRE scenarios becomes more pronounced.

Investment requirements to achieve a 10 percent process efficiency improvement or a 10 percent capital cost reduction may differ of course, but an implication may be that research and development (R&D) investments allowing for lower capital costs of electro-commodities could receive more attention in high VRE scenarios. In a low VRE scenario with higher average electricity prices, improving process efficiencies may represent a more effective path to reduce unit costs.

Groundwater Desalination and The Role Of Product Storage

The second case study extends our discussion of new electro-commodities by weighing the relative merit of investments in additional product storage assets in a low versus high VRE scenario. Long intervals of very low wholesale electricity prices may induce industrial end users to produce more of a product during low-cost hours, place it into storage, and discharge it from storage during high-cost hours. It is quite likely that industrial end-use customers already take advantage of this price difference between periods, but we examine how the optimal investment in storage may change with a substantial increase in electricity price variation in a high VRE scenario.

Though not evaluated in detail here, the concept of increasing storage capacity of finished energy-intensive products could also be extended to storing energy-intensive intermediate product inputs. These may include, for example, process heat for some industrial applications, or in our example, preparing desalination operations by increasing water pressure by pumping water uphill.

Assumptions

We use production data from the Kay-Bailey Hutchinson (KBH) desalination plant located in El Paso, Texas. The plant desalinates brackish groundwater using reverse osmosis (RO) membrane technology. Desalination is very electricity-intensive, requiring great amounts of electricity to pump the water and push it through a membrane, thereby separating the brine from the water (Fiorenza, Sharma, and Braccio 2003).[20] The plant operates below its maximum capacity for most of the year and provides a small portion of the total water supply to the El Paso water system (Delgado, Beach, and Luzzadder-Beach 2019). The plant, however, is the largest inland desalination plant in the United States.

Given the complexities of a regional water system, we opt for a simplified analysis in which the desalination plant operates in a wet year (low demand) and a subsequent dry year (high demand) as illustrated in Figure 15. We assume the plant takes dispatch orders from the regional El Paso water authority, however our decision framework allows the plant to produce above its regular dispatch levels and inject water into storage during the wet year. The plant operator may later discharge from storage to partially meet its dispatch requirement in the dry year instead of running the plant. Within a given month the demand for desalinated water is assumed to be constant and does not vary by hour.

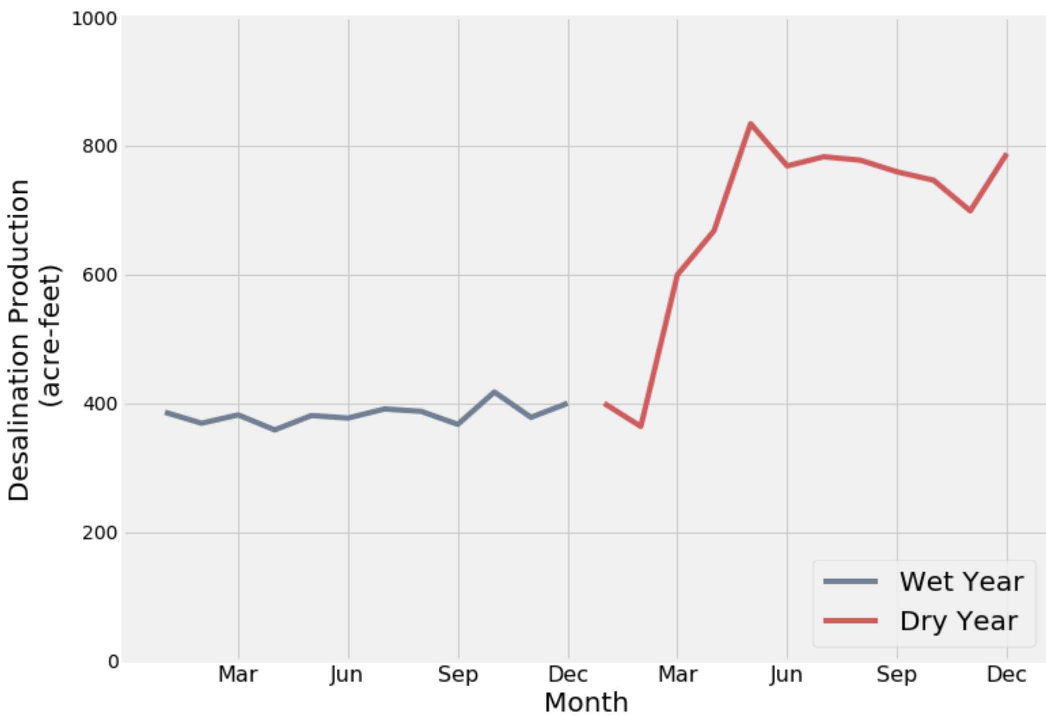

Figure 15. Monthly demand for desalinated water in El Paso across two hypothetical years

Our review of the KBH desalination plant finds the capital cost to be $91 million dollars and the capacity of the plant to be 27.5 million gallons per day (Arroyo and Shirazi 2012). We know, however, that much of the plant's capacity is currently underutilized. Storage costs vary with the reservoir size and the type of lining used. In general, the storage costs for water are low compared to storage costs of other energy goods. Our assessment assumes a constant reservoir cost of $200 per acre-foot of capacity with no reservoir lining (Waters Jr. 2001).

[20] A separate important part of the brackish groundwater desalination process is the deposition of the waste product: brine. Plant operators pump the waste brine product back into aquifers, which must be kept carefully isolated from fresh groundwater resources.

Findings

Even though desalination is a very energy-intensive process, the largest component of the levelized cost of desalinated water seems to be the upfront capital investments of the desalination plant itself, and even sizeable savings in operational costs reduce the delivered water costs only modestly. Unlike seawater, brackish groundwater contains a low salinity content and therefore requires less pressure and less energy input to squeeze the water through the membranes. For context, we estimate the capital and maintenance cost of the KBH plant to be approximately $385 per acre-foot and the electricity cost to be $30 per acre-foot. Nevertheless, we find that investments in product storage capacity lead to higher savings in a high VRE environment because of increasing price variability relative to a low VRE scenario.

Figure 16 demonstrates that despite the requirement of additional capital costs, investments in storage reduce the levelized cost of desalinated water across all scenarios by approximately $5–$9 per acre-foot due to large savings in operating expenses. Although this opportunity exists already in the low VRE scenario, it becomes even more salient with higher VRE penetrations. The savings from investing in storage as a share of electricity operating costs almost double to 37 percent relative to 20 percent in the low VRE scenario, especially in the high solar VRE scenario that features the most low-priced hours. We find utilization rates of storage (the number of hours of pumping into storage) are also highest in the high solar VRE scenario, followed by the balanced and high wind VRE scenarios. Utilization rates are 19 percent, 11 percent, and 6 percent for the three high VRE scenarios, which correspond closely to the percentage of hours featuring prices less than $5 per MWh.

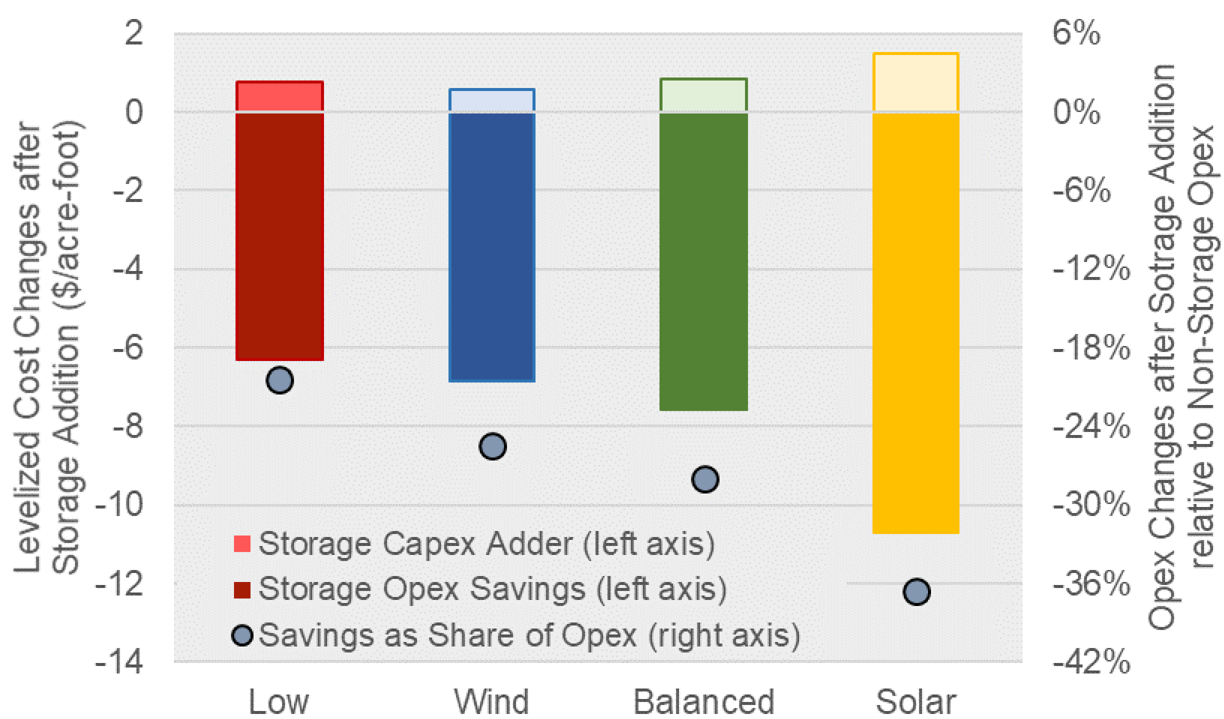

Figure 16. Reduction in levelized costs in absolute and relative terms due to product storage additions

The optimal size of the storage reservoir can change with higher VRE penetrations relative to a low VRE scenario, but the directionality depends on the dominant VRE technology. Figure 17 highlights that the size of the added optimal storage reservoir size in the high solar scenario is approximately twice the volume of the added reservoir in the low VRE scenario. Somewhat surprisingly, the size of the added reservoirs in the high wind scenario is slightly smaller than the low VRE storage size. This is because the overall price variation in the high wind scenario is comparable to the ERCOT base system (already featuring 16 percent wind penetration) and because peak-to-off-peak price ratios actually decrease with growing wind shares in ERCOT.

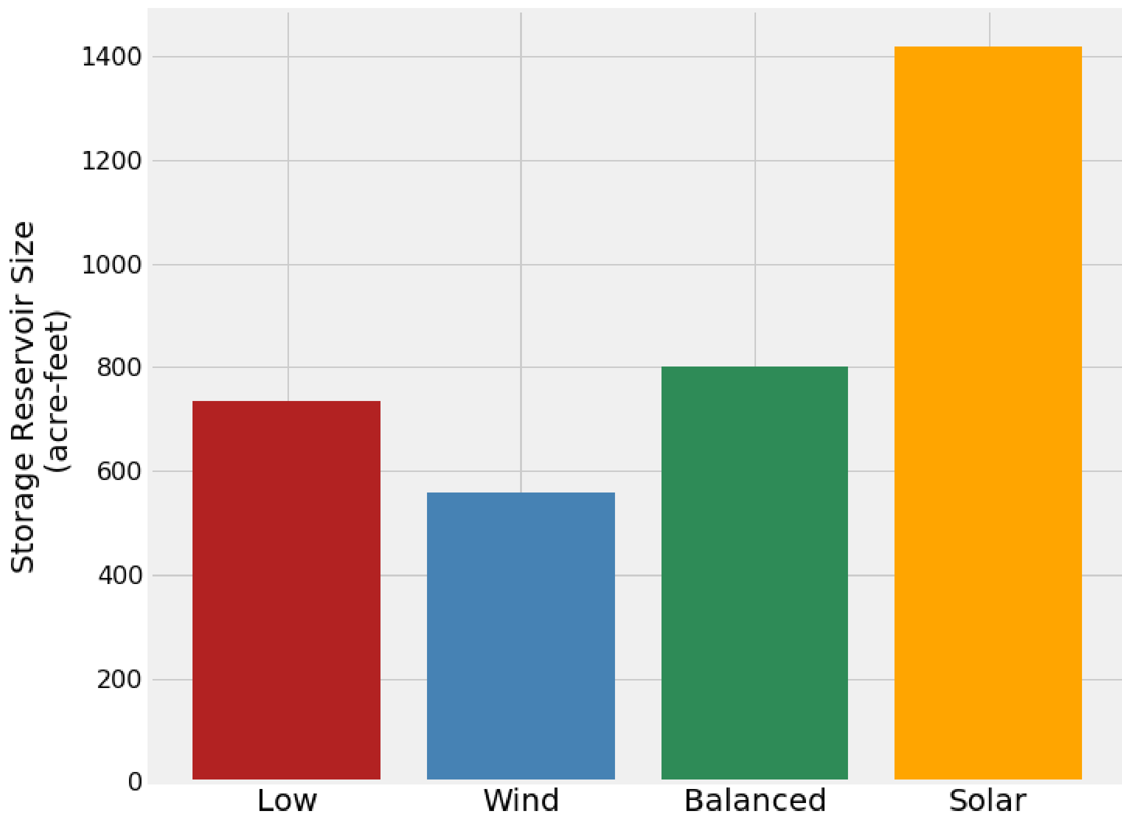

Figure 17. Optimal storage reservoir size for a desalination plant in El Paso across scenarios

District Energy Systems with Increased Fuel Flexibility

Our third case study examines existing industrial processes that rely primarily on one or more fossil fuels (e.g., natural gas and oil) but that may benefit economically from the ability to fuel-switch and increase their use of electricity in a high VRE scenario, particularly during hours with very low wholesale electricity prices. In this setting, the end user weighs the trade-off of higher capital investment in fuel-switching technology against reduced operating costs from cheaper electricity relative to natural gas or other fuels. We compare the levelized cost of investing in the fuel-switching technology relative to traditional fuel technology investments in each of the VRE scenarios. Our case study looks at district energy (DE) systems that provide heating and cooling services to clusters of buildings using steam pumped through a network of insulated pipes. The heating and cooling services are typically produced by heating water in a boiler with natural gas, but many (older) systems also produce steam or purchase it from cogeneration assets. Estimates of the number of DE systems in the United States range from 660 to over 5,800 (Cooper and Rajkovich 2012; U.S. Energy Information Administration 2018a). The most common applications of DE in the United States are on college and university campuses, office parks, and some urban clusters. Even though our analysis focuses on electric heat pumps to supply thermal energy, there are other industrial processes in which heat provided by electricity can supplement fossil fueled heat; for example, resistance heating, microwaves, induction, and electric arc furnaces (Sandalow et al. 2019).

The decision to fuel-switch in a DE system hinges upon the ability to produce heating and cooling services with an electric technology such as industrial-scale electric heat pumps. We note a growing interest in using large scale heat pumps for DE applications, especially in Europe (David et al. 2017; Lund et al. 2014; EHPA 2019), but also in the United States (Stagner 2018; Ahern 2019). The heat pumps can use a variety of heat sources, including large bodies of water, industrial waste heat, or even sewage heat. Older DE systems usually rely on steam as a thermal transfer medium and may require additional network upgrades to allow for the use of water as a heat carrier, as was recently done in cities like Munich, Salzburg, and Copenhagen (Lund et al. 2014). In this scoping analysis we exclude these additional upgrade costs and limit ourselves to capital costs of the actual heating technology, as described below. Substantial opportunities also exist to incorporate heat pumps in individual buildings instead of using them at the district level alone, but for scope purposes we limit ourselves to a discussion of aggregate district heating and cooling profiles.

Our quantitative assessment illustrates the relative economics of new investments into gas-based boilers or heat pumps at the time of unit failure or end of life of a unit. We compare the levelized cost of DE systems produced with no electric heat pumps (the *all-gas case*), and some supplemental amount of electric heat pumps (the *hybrid case*). This analysis is slightly more complex than the simple production of an electro-commodity, as the decision-maker is now confronted with multiple time-varying fuel costs and time-varying demand for a product (heat or cooling) that we do not assume to be flexible. We examine the example of hypothetical college campuses across the United States to evaluate different natural gas price environments, contrasting heating and cooling profiles and associated load factors in other climatic regions and distinct wholesale price dynamics in our four ISOs. Appendix B.2 provides a more complex case study examining fuel-flexibility benefits with increasing VRE penetration for a district energy system in Manhattan, NY.

Assumptions

The stylized college campus DE systems are placed in two representative locations in each of our four ISOs: San Francisco and Bakersfield in CAISO, Kansas City and Sioux City in SPP, Dallas and El Paso in ERCOT, and New York City and Buffalo in NYISO. To estimate heating and cooling demand, we again leverage geographically differentiated hourly load profiles from the Building America Simulation for a typical meteorological year (Wilson 2014). Notably, we do not account for potential synergies in coincident heating and cooling demands but assume that those services are provided independently. We select an aggregation of 25 secondary-school buildings and 10 mid-rise apartments as a proxy for university buildings and dorms. Therefore, the size of a representative college campus does not vary across each region, but the demand for heating and cooling varies with the local climate.

We estimate the capital cost of the industrial scale electric heat pump based on a literature review to be $800 per kW of installed capacity (Kontu, Rinne, and Junnila 2019; Pensini, Rasmussen, and Kempton 2014). The efficiency of the pump, typically referred to as *coefficient of performance (COP),* is assumed to be 5.0 (Kontu, Rinne, and Junnila 2019; Nowak 2018; Østergaard and Andersen 2018; Pass, Wetter, and Piette 2016). We assume a constant COP during all months of the year and across all locations in the United States. In practice, the COP of the pump varies based on ambient temperatures (Østergaard and Andersen 2018). As the temperature difference between the heat pump intake and the delivered heat increases, the COP of the pump decreases.

As explained previously, we test an all-gas system and a DE hybrid system with an electric heat pump capacity of 20 MW for the college campuses, translating to about 20 percent of the system's peak demand. In both cases we assume a 10 percent reserve capacity supplied by natural gas boilers. Details about the relative installed capacity of natural gas boilers, and heat pumps are described in Table B-3 in Appendix B.

Findings

Results for the college-campus analysis of fuel-switching in DE systems are shown in Figure 18. The results are ordered by the annual natural gas fuel expenses in the gas-only scenario (x-axis). The rationale is that all-gas DE systems are expected to be most attractive in environments with either few heating and cooling days, low natural gas prices, or jurisdictions without carbon penalties, i.e., regions to the left along the x-axis of Figure 18. Under those circumstances the overall fuel expenses are low, and the upfront capital requirements of the relatively cheap boiler systems allow for low levelized costs. In contrast, the performance benefits of heat pumps can make up for the higher upfront capital costs and deliver lower levelized costs in areas with high heating and cooling demands and high natural gas costs.

Hybrid systems tend to perform worse than gas-only systems in locations with low natural gas expenses (e.g., El Paso), but better in regions with higher natural gas expenses (e.g., Sioux City through Buffalo).

The all-gas system is the most expensive system option in five out of our eight simulated college campuses (Kansas City, Sioux City, Bakersfield, New York City, and Buffalo), which are concentrated in regions that have high annual natural gas expenses. The logic is intuitive: investing in the flexibility to switch between electricity and natural gas is most economical in locations with high DE demands (allowing the heat pump efficiency gains to shine and increasing the hours over which the higher capital costs can be recovered) and high natural gas prices.

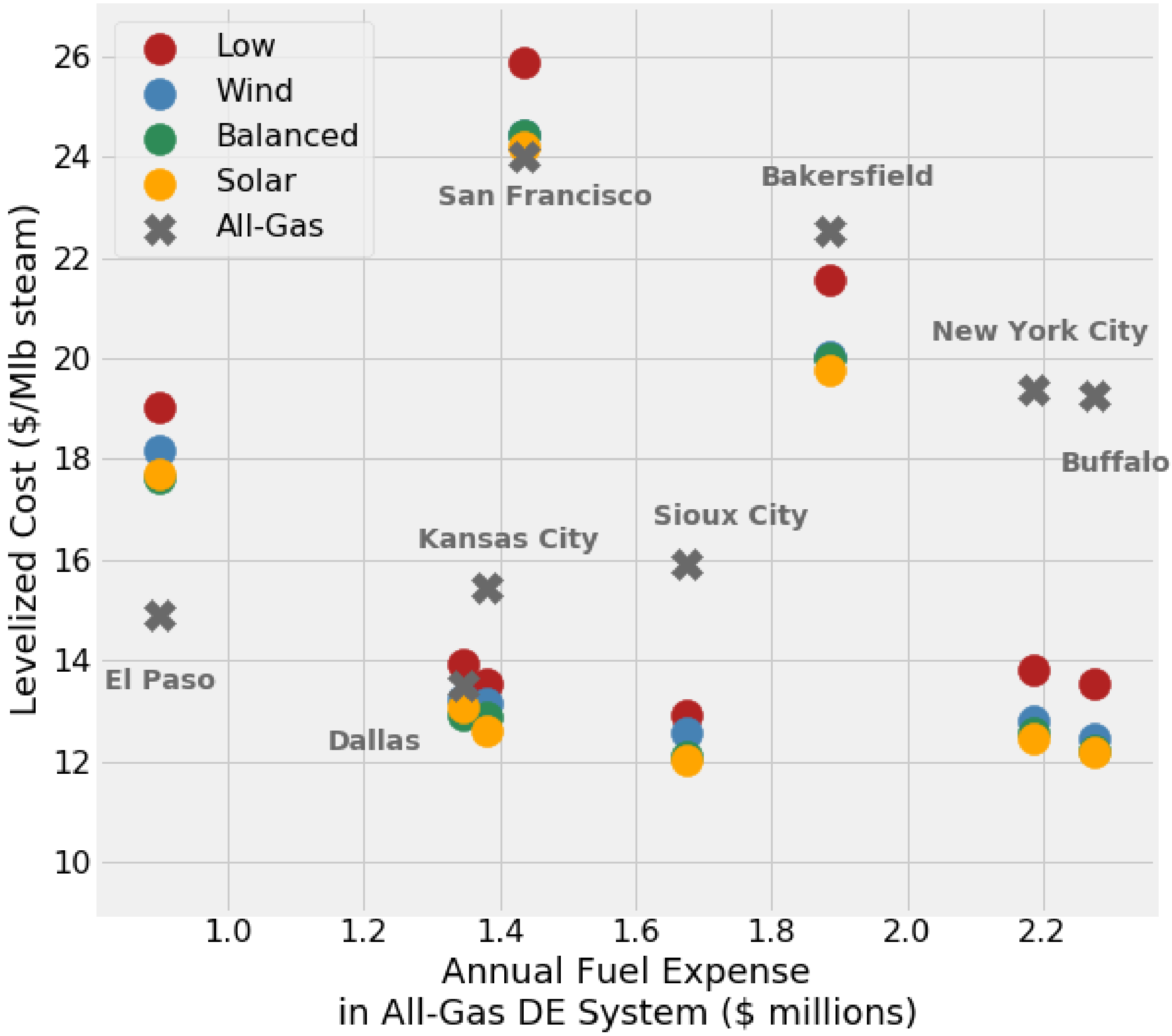

Figure 18. Levelized energy costs for college campuses across ISOs, DE configurations, and scenarios

With our assumed system characteristics, the decision of whether to invest in a hybrid or all-gas system is rarely different between the low VRE and high VRE scenarios. That said, we do find that the levelized costs of hybrid DE systems decrease with higher VRE penetrations across all examined locations. The high solar scenarios tend to yield the lowest levelized costs for DE systems that incorporate heat pumps. Results may be more dynamic with different heat pump efficiency and capital cost assumptions (or even cheaper resistive electric heaters) or if the heat pump capacity share is not assumed to be constant at 20 percent across all locations but is allowed to vary. We reiterate that our evaluation represents only a scoping analysis, which may not fully capture all system upgrade costs or available performance benefits and which would benefit from more detailed thermal load modeling that may reveal larger performance differences between our low and high VRE scenarios. The case study of a DE in Manhattan, NY (Appendix B.2) shows in contrast that hybrid DE systems with heat pumps only become cost-effective with higher VRE penetrations.

3.4 Discussion

Periods of low prices in high VRE scenarios present an opportunity for large energy users to reduce operating expenses through shifting consumption to these periods. The overall unit cost, however, also depends on the size of the capital expenditure and the utilization of capital investments. Higher utilization rates lower per-unit capital costs but increase operating costs, as production extends the hours of electricity use to those with increasingly higher prices. High VRE scenarios increase the frequency of low prices, improving the economics for large energy users who can take advantage of them.

A general implication is that the relative importance of operating efficiency and capital investments changes with more frequent periods of very low energy prices in high VRE scenarios. In cases where lower capital investments result in equipment that is less energy efficient, high energy prices traditionally drive up per-unit production costs. In a low energy price environment the penalty for less efficient equipment is reduced and, combined with lower capital costs, overall commodity costs may decrease on a per-unit basis. In an electricity market with highly varying prices, capital investments that enable access to lower cost energy—such as investments in flexibility—will produce bigger per-unit savings than operating efficiency investments.

While much focus is on energy storage to smooth out the variability of wind and solar generation, many end use processes can also deploy storage mid-process or on the product end to manage variability. Commodities, treated water, and heat often can be stored at lower cost than storing electricity. Efforts to enable variable production rates can hence be an attractive alternative to investing in electricity storage.

Finally, it should be noted that electricity prices in a competitive market will always be fluid. Periods of low prices will attract consumers, thus driving up demand and ultimately prices in those hours. Higher prices will then incentivize more deployment of the generation causing the periods of low price, such as midday solar power. In this study, we only look at the marginal impacts and do not seek to find equilibrium prices. Our results do suggest, however, that changing wholesale price dynamics may have a large enough effect on production costs that industrial end users may want to evaluate production decisions differently in high VRE scenarios. Large capital investments that are based on ever-changing wholesale electricity price dynamics may also carry some risks that investors want to consider carefully, and they may wish to evaluate opportunities they might use to hedge these risks. Nevertheless, investments that enable more flexible operations may provide new opportunities in a world with increasing wholesale price volatility.

3.5 Conclusion

As wind and solar rapidly grow, many have noted the impacts of VRE on wholesale power markets. In this section we have sought to show how large energy consumers could respond to these new price dynamics.

The large energy consumers who will benefit the most from new pricing environments are those that can shift energy consumption to periods of low-priced electricity, either by adopting new technologies that allow for substitution from another fuel to electricity, by altering production processes that enable more flexible electricity consumption regimens, or by adding storage, either up-front, mid-process or on the product end.

We have shown that high VRE wholesale electricity prices can decrease costs for hydrogen production 13 to 40 percent relative to a low VRE scenario and that the relative weight of production factor costs shift from Opex to Capex as cost-minimizing utilization rates of production equipment can decrease dramatically. Less flexible production processes that require longer consecutive run hours have in contrast a stronger cost impact in high VRE scenarios compared with our low VRE baseline. We have also demonstrated that research and development efforts for generic electro-commodity manufacturing may be most fruitful in a high VRE environment when focused on a reduction of up-front capital expenses instead of increasing process efficiency.

Extending the electro-commodity discussion to product storage with the example of a desalination plant illustrates growing cost saving opportunities with higher VRE penetration, as minor increases in required capital costs are offset by larger reductions of operating costs. The optimal storage size also tends to increase in scenarios with strong solar growth.

Weighing flexibility gains from investments in fuel-switching capability against increased upfront capital costs led to mixed results in our example of college campus district energy systems across the United States. While our analysis indicates general economic performance benefits for the use of hybrid gas boiler / heat pump systems in the high VRE scenarios compared with the low VRE scenario, we did not find a meaningful change in the relative attractiveness of heat pumps versus boilers in the stylized college campuses. In both low and high VRE scenarios the adoption of auxiliary heat pumps seemed economically attractive for most regions with combinations of high natural gas prices and high heating and cooling demands like New York City and Buffalo (annual natural gas fuel expenses equal about $25,000 per MW of maximum heating demand).

However, not all costs and technical issues have been considered in our scoping analysis and full economic assessments require more detailed engineering level analysis. For example, we have assumed that industrial customers have access to wholesale energy and capacity prices and have ignored potential complications stemming from potential demand charges. These limitations not withstanding our case studies have shown consistently that more flexible energy consumption can unlock greater economic gains as VRE penetrations increase and wholesale electricity prices become more dynamic.

4 Electricity Retail Rate Design

4.1 Introduction

Fundamental price characteristics of the power system change with high shares of VRE. In particular, high VRE scenarios increase variability in wholesale power prices. These changes can assume rather regular diurnal patterns (especially with high solar penetrations) and/or lead to an increase in irregular price volatility (especially with high wind penetrations). This section explores how changes in wholesale price dynamics in high VRE scenarios affect the economic efficiency of various retail rate structures.

Due to the regulated nature of the electricity industry, decision-makers like public utility commissioners or rural cooperatives set retail electricity prices through a process called *rate design*. Unlike the price setting mechanisms of competitive wholesale markets, a menu of design principles determines the rates a retail customer pays (Bonbright 1961). The purpose of our analysis is to evaluate if rates designed under conditions of low levels of VRE continue to achieve their intended objectives in a scenario with high penetration levels of VRE.

When the wholesale cost of energy generation varies moderately or in a predictable manner, the trade-off between efficient pricing and other rate design goals like simplicity and bill stability might not be substantial. However, higher levels of VRE penetration will drive both changes in diurnal price profiles and greater price volatility in wholesale energy markets. Given these changes in wholesale price patterns, what new aspects might a retail rate designer consider when drafting the next generation of retail rates? Although a recommendation of the "perfect" rate design under high levels of VRE penetration is beyond the scope of this report, we do illustrate potentially beneficial ways current retail rate design practices could change in a high VRE scenario to improve economic efficiency.

Our analysis begins by identifying rate design decisions that are long-lasting, in particular the volumetric and temporal aspects of the retail rate structure. These drive consumer decisions on new appliance purchases, building energy efficiency investments, and vehicle selection. We follow with a discussion of the broad objectives of rate design and the decision-makers who determine them. Next, we outline the cost-benefit analyses that decision-makers use to evaluate trade-offs between rate designs. We then demonstrate how sensitive these trade-offs are to high VRE penetrations. Finally, we illustrate changes for decision-makers to consider when preparing for a higher VRE scenario relative to current VRE penetrations.

The results of this scoping study should be considered primarily as a way to explore how retail rates could change in response to changing price dynamics with high VRE scenarios, and not as an authoritative assessment of what all-in retail rate prices will be in the future. More detailed analysis would be required to assess how residential, commercial, and industrial customers might be able to capture more economic value from rate design in a high VRE scenario. Similarly, further analysis would benefit from considering the impacts of T&D costs on rates in various future VRE scenarios.

4.2 Qualitative Summary of the Decision-Making Process

Long-Lasting Rate Design Decisions

The rate design process is embedded within the greater process of public utility regulation. In a textbook economics understanding, prices in a competitive market are set at marginal cost (Boiteux 1960; Borenstein and Holland 2005; Joskow 1976). In the absence of competition, regulation determines the prices a natural monopoly may charge (Bushnell, Mansur, and Saravia 2008; Lazar 2016a). The most common form of electric utility regulation in the United States is *cost of service regulation*. It is important to understand that VRE penetration levels will affect some structural and long-lasting fundamentals of cost of service regulation, while other regulatory decisions can be updated iteratively as the system share of VRE grows.

While many factors affecting retail rate design are determined by cost of service regulation, we anticipate that rising shares of VRE and associated changes in wholesale electricity market dynamics will lead to the greatest changes to the temporal and volumetric structure of retail rates. In designing rates for customers, a rate designer must strike an appropriate balance between rate structures that are complex but economically efficient versus structures that are easy to understand. Increasing VRE shares and increasing price volatility in wholesale energy and capacity markets will likely drive a wedge between rate structures that emphasize economic efficiency and rate structures that emphasize simplicity.

The decision to deploy new retail rate structures to customers is a long lasting-decision because rate designers must be careful to not change the fundamental structure of retail rates too frequently. Doing so would lead to customer confusion and an inability to mitigate energy expenses with enduring investments (e.g., energy efficiency upgrades). Other factors that affect rate design, such as the revenue requirement[21] and the allocation of costs to customer classes[22], may be updated iteratively as VRE shares increase.

[21] In its simplest form, cost of service regulation sets the price levels of retail rates by dividing the utility's revenue requirement by its total sales. As general rate cases reauthorize a utility's revenue requirement roughly every three years, the level of retail prices adjusts upward or downward. Because the cost of purchasing or generating electricity can vary frequently and unpredictably, retail rates typically feature fuel adjustment clauses to adjust the level of prices in between rate cases. So, while the determination of a utility's revenue requirement plays an essential role in determining retail prices, it is not a long-lasting decision, and the impacts of rising VRE penetrations can be regularly addressed during general rate cases.

[22] Similar to the revenue requirement, high VRE penetrations in wholesale electricity markets will likely not influence how decision-makers think about allocating revenue requirements to customer classes. Following the method of cost causation, customers that contribute larger shares of costs to the utility's operations would pay higher bills. Costs are allocated to a customer class based on three principal metrics: the number of customers in the class, total sales to that customer class, and its contribution to various measures of peak demand. We do not expect increasing shares of VRE to influence how a decision-maker allocates utility costs among its customer classes.
One exception is distributed energy resources producing behind-the-meter generation. There is an extensive existing literature on how growth in distributed solar affects cost allocation between classes (Brown and Lund 2013; Costello 2015; Darghouth et al. 2016; Hledik 2014; McLaren et al. 2015; Satchwell et al. 2014) and we exclude it from our analysis as we focus on changes in wholesale market dynamics. Given the uniqueness of how distributed resources interact with the distribution grid, decision-makers may consider using the principles of cost causation to assess whether such customers require a specialized rate class.

Temporal and Volumetric Structure of the Retail Rate

The most common rate design in the United States is the *flat rate* or an *inclining block rate,* which is not differentiated by time but rather by consumption (Cappers et al. 2016). *Time-of-use (TOU)* rates charge customers a different hourly rate according to a predetermined schedule. TOU rates may differ in the number of predetermined pricing periods per day and the price ratios between the periods.

Less than 5 percent of customers in the United States are enrolled on time-based rates (Cappers et al. 2016; Hledik, Warner, and Faruqui 2018), though the investor-owned electric utilities in California are transitioning customers to default TOU rates and there is international precedence for mandatory TOU rates (for example in Italy and Ontario, Canada). Despite the low TOU enrollment rates in the electricity sector, there is extensive experience in the U.S. with more complex rate structures that goes well beyond the electricity sector.[23]

Unlike TOU rates which are static, *critical-peak pricing (CPP)* programs communicate to customers on an incident basis when wholesale spot market prices are extraordinarily high. Under a typical CPP program, customers are notified a day in advance if an “event day” will be called. These may be layered over a flat, non-TOU rate form (Maryland) or on top of a TOU rate form (California, France). It is worth noting that similar levels of economic efficiency may be achieved as well with the alternative of coupling flat rates with effective demand-response programs, which closely resemble CPP rates.

Oklahoma Gas and Electric (OG&E) offers an innovative form of CPP called *variable-peak pricing (VPP).* The program allows the utility to charge an even more granular price signal to customers than the conventional CPP rate. Several utilities in and outside the United States offer innovative *real-time pricing (RTP)* programs, which expose customers to real-time fluctuations in market prices (Barbose, Goldman, and Neenan 2004).

Principles of Rate Design

In *Principles of Public Utility Rates*, James Bonbright authored the most enduring set of rate design principles, of which many are still widely cited today. These principles stipulate that a rate should offer a fair return to the utility, discourage inefficient or wasteful consumption, not unduly discriminate against types of customers, be simple enough to be understood, and generally provide stable bills from one period to the next (Bonbright 1961).

It is up to the rate design expert to choose how each of these principles is weighted when crafting the rate. In practice, no single rate design expert determines the final weighting. More likely, a group of experts presents evidence and debates if a proposed rate adequately satisfies the objectives of rate design. Public utility commission staff, utility experts, consumer advocates,

[23] For example, Lo et al. (2019) draw a parallel to rate design in the telecommunications industry which features a low-marginal cost and high-capital cost environment, potentially mimicking high VRE futures in the electricity sector. The authors propose service-based contracts for the electricity sector. Ride-sharing services also offer complex rate structures, including demand and time-based elements.

environmental stakeholders, industry representatives, and the public often form the diverse group of rate design experts that contribute to the final decision.

Our analysis focuses on the trade-off between rate simplicity and economic efficiency because this trade-off is most sensitive to VRE penetrations. We demonstrate in the following sections that fundamental changes in the dynamics of wholesale electricity prices will drive a growing wedge between these two rate design objectives as solar and wind shares increase in the grid.

Evaluating Rate Design Performance

To quantitatively assess the economic performance of a rate design subject to varying VRE penetrations, we need a method to measure its efficiency. In economics, the concept of *deadweight loss (DWL)* represents the lost economic value caused by a market failure. In the case of retail electricity pricing, rates often do not reflect marginal cost because the utility business is a natural monopoly and marginal costs can vary substantially even within hours (Joskow and Wolfram 2012; Mays and Klabjan 2017). A consequence of this is that if rates exceed the marginal cost, consumers will tend to consume too little electricity even though it is cheap to supply. Likewise, if rates are below marginal cost, consumers will tend to consume too much electricity at times when electricity is expensive to supply, resulting in wasteful consumption of electricity. Both the forgone and excessive consumption constitute an overall economic loss to society and can be quantified by the DWL.

We choose the metric of DWL as our central measure of economic performance of a rate, which allows us to compare the relative merits of various rate designs under different wholesale price environments. It is important to note that a rate performs better when it decreases DWL. Rates with lower DWL allow customers and utilities to capture greater value from electricity consumption and production. For example, customers may be more willing to purchase and charge electric vehicles if rates reflect the near-zero pricing events associated with times of excess VRE generation.

The amount of DWL associated with a given rate structure depends not only on the magnitude of the divergence between the retail rate and marginal cost, but it also depends on the *price elasticity of demand.* Inefficient rate structures will result in greater levels of DWL if a customer's demand is more price responsive. In general, empirical studies have shown that customers are mostly price inelastic to electricity prices in the short run (several months to a year) but are more price elastic in the long run (Charles River Associates 2005; Deryugina, MacKay, and Reif 2018). Price elasticity also increases with the presence of enabling technologies that allow customers to better control their consumption, like programmable thermostats, grid-integrated water heaters, and smart electric vehicle chargers (Cappers and Scheer 2016; Faruqui, Sergici, and Warner 2017; Lazar 2016b).

The equation below shows the calculation of DWL for a given hour (*h*).

$$DWL_h = \frac{1}{2\hat{s}}\left[Q_h * \left(\tilde{P}_h - P_h\right)\right]$$

As explained in the first paragraph, DWL is a function of the divergence in the rate ($\tilde{P}_h$) from the wholesale price (P_h), as well as the slope of the customer's inverse demand curve ($\hat{s}$). The slope of the inverse demand curve is determined by the price elasticity of demand; more detail on this calculation method may be found in Borenstein and Bushnell (2018).

4.3 Quantitative Analysis of Retail Rate Performance under High VRE Penetrations

Our quantitative assessment first examines how growing VRE penetrations will change the economic performance of existing retail rates. Subsequently we highlight how certain structural changes to rates will enable a rate-maker to maintain efficient and effective rates in a high VRE scenario.

Analytical Approach

Measure of Rate Performance: Minimize Deadweight Loss

Our analysis follows the standard economic approach of estimating the reduction in economic efficiency from a given rate structure by comparing it to the counterfactual of a customer facing the true marginal cost of electricity. We assume wholesale energy markets are competitive and use hourly wholesale energy and capacity prices to approximate marginal cost.

As explained in this scoping report's introduction, wholesale energy and capacity prices are simulated for four different market regions and four different VRE scenarios using a capacity-expansion model (Seel, Mills, and Wiser 2018). We simulate equilibrium prices in the year 2030 and distinguish between a low VRE penetration scenario and three scenarios that increase VRE penetration exogenously to at least 40 percent. The three VRE scenarios that increase VRE penetration feature 30 percent wind generation and 10 percent solar, 30 percent solar and 10 percent wind, and a mix of 20 percent wind and 20 percent solar each. The low VRE scenario freezes VRE penetration at 2016 levels.

We perform our analysis in three distinct steps: First, we choose optimal rate parameters (described in detail below) by minimizing DWL given the wholesale price dynamics of our low VRE scenario—allowing us to compare the relative economic efficiency of different rates in a VRE setting similar to that of today. Subsequently we measure the performance of this low-VRE optimized rate against the wholesale prices of our high VRE scenarios and quantify changes in economic efficiency in this new environment. Finally we reassess our rate parameters in order to optimize the rates for the three high VRE scenarios (solar-dominated, wind-dominated, or balanced wind and solar) and highlight how they differ from the original low VRE rates.

Analytical Approach

1. Optimize rates for low VRE future (minimize DWL).
2. Assess how those rates perform in high VRE futures (quantify DWL changes).
3. Optimize rates for high VRE futures (minimize DWL) and highlight changes to the original rate structure.

Throughout each step, we structure rates to be revenue-neutral, meaning the load-weighted average price of any rate structure equals the load-weighted average of the wholesale generation and capacity prices. Revenue-neutral rates imply all deadweight loss is only a function of the time-varying component of wholesale prices because a utility cannot charge a rate that is on average higher or lower than the average wholesale price.

It is important to note that we emphasize directional changes in DWL between different VRE penetration levels. We do so because the absolute magnitude of the DWL is sensitive to our price elasticity assumption. However, we use equivalent price elasticity assumptions in scenarios with high VRE and scenarios with low VRE penetration, enabling us to draw comparisons across VRE scenarios.

Limitations

Retail rates include other charges beyond those that recover generation and capacity costs. Illustrated in Figure 19, our quantitative assessment excludes these other charges, like taxes and special rate riders, fixed charges, and rates for T&D, which are important components of a customer's electric bill and may vary in a high VRE scenario (Cappers and Murphy 2019). We exclude such charges because our production-cost model simulates generation and capacity prices in each scenario but does not simulate additional T&D costs. In cases where peak T&D costs (aggregated at the ISO-level) coincide with peak generation and capacity costs, the exclusion of T&D rates would not change the optimal peak and off-peak period of a given rate. We expect these aggregate costs frequently to coincide but do not have confirming simulation evidence. Customers typically pay for T&D services via flat rates, fixed charges, or a combination of both. However, efficient T&D pricing implies that rates should reflect hourly locational marginal prices (LMPs) and fixed charges should vary based on customer size (Wolak 2019).

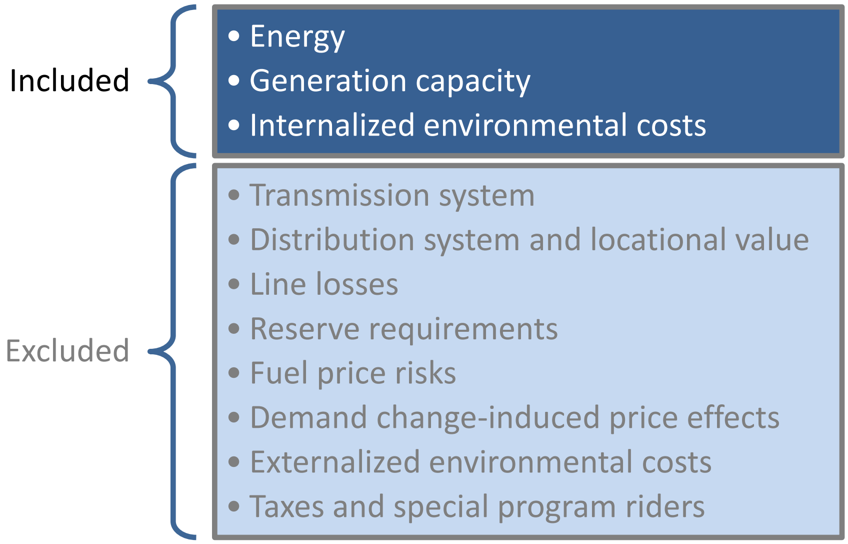

Figure 19. Selection of retail rate charges in analysis

A consequence of having insufficient data to model all retail rate components is that we cannot speak about the absolute magnitude of future retail rates in each of our four regions. While the average combined energy and capacity prices decline, these reductions may be offset by either additional investments in T&D infrastructures or potential investment incentives that may be necessary to achieve the exogenously set VRE share.

Another limitation of our approach is our degree of specificity with respect to customer class. Each ISO contains a diversity of customer types with unique load characteristics. Some of these unique loads necessitate separate rate classes. We conduct our analysis at the aggregate ISO level, thereby neglecting differences among customer types. We do so because our goal is not to identify specific impacts to each customer type, but rather to identify broader system-wide changes that may impact general retail rate design practices in the future. Further research may study how high VRE scenarios affect rate design within customer classes and sub-classes, like customers who install onsite generation. We describe rate performance mostly on a relative basis (in percentage or $/MWh terms) which allows us to discuss rate effects without needing to specify rate adoption levels of individual customer classes.

Our analysis does internalize some externalities associated with electricity generation, but does not capture all external environmental and health costs. Our simulation of wholesale generation and capacity prices in the year 2030 include a carbon price of $24/ton of carbon dioxide equivalent (t CO_2) and $50/t CO_2 in NYISO and CAISO, respectively, stemming from existing legislation in these two regions. However, our analysis is further limited by omitting the full social accounting of electricity generation in all four market regions (Borenstein and Bushnell 2018).

Analyzed Rate Structures

We select four rate structures to measure deadweight loss in low and high VRE scenarios. These rate structures alone by no means encompass the full range of rate designs offered to customers today. However, they represent a variety of rate structures, allowing us to analyze the impact of high VRE penetration levels on retail rate design.

As we analyze our candidate rates across the low and high VRE scenarios we vary a number of parameters to minimize DWL. These key parameters include the hours and price ratios of the peak period, off-peak period, and super-off peak period, which are differentiated by summer and non-summer months. More details on the parameters may be found in Table C-1 and Table C-2 in Appendix C.

In our analysis of these rate structures, we assume the same price elasticity of demand across each VRE penetration scenario. However, we assume a higher price elasticity during CPP events compared to static TOU and flat rates. Previous research shows customers are more willing and able to respond to short-term pricing events when prices are substantially elevated above normal levels (Faruqui and Sergici 2010). We assume a price elasticity of 0.10 during CPP events and 0.05 during all other hours.

Flat Rate

The first pricing structure we assess is the flat volumetric rate. When we design this rate, it equals the load-weighted average of the wholesale energy prices and the capacity prices that we allocate in equal parts to the top 100 peak net load hours.

Time-of-Use Rate (2- and 3-Period)

We analyze two types of TOU rates. One TOU rate features two pricing periods: an on-peak and an off-peak period. The other includes a third pricing level during super-off peak periods. We allow the TOU rates to vary seasonally by summer and non-summer months.

Critical Peak Pricing + TOU

The fourth and final rate design layers a CPP rate structure on top of a three-period TOU rate. Under this type of rate design, the dynamic nature of the critical peak price sends customers a price signal during the top 1 percent of hours when wholesale prices are high and grid resources are exceptionally constrained. An important assumption to our modeling of this rate design is that we allow CPP events to be called with perfect foresight.

We omit fixed charges and demand charges from our discussion of retail rate design because these rate structures are typically designed to recover distribution costs (Wood et al. 2016), though demand charges may recover energy costs as well. We discussed in a previous section that our wholesale market simulation focuses on energy generation and capacity prices but does not model distribution cost changes with increasing VRE penetrations.

Results

Optimal Rate Designs in a Low VRE Scenario

The first step in our analysis identifies rate structures that minimize economic inefficiency (captured as DWL) given low penetration levels of VRE. We later test how these optimal rate designs in a low VRE scenario perform at higher levels of VRE penetration. We expect the structures to mirror the types of time-based rate offerings we see available to customers today. Figure 20 shows a snapshot of efficient two-period TOU rates during the peak summer months, as well as average combined energy and capacity prices for comparison. Summer peak windows in SPP, CAISO, and ERCOT occur in the afternoon and early evening hours. NYISO's peak period begins earlier in the morning and lasts for most of the day and night, similar to ConEd's existing time-based retail rate.

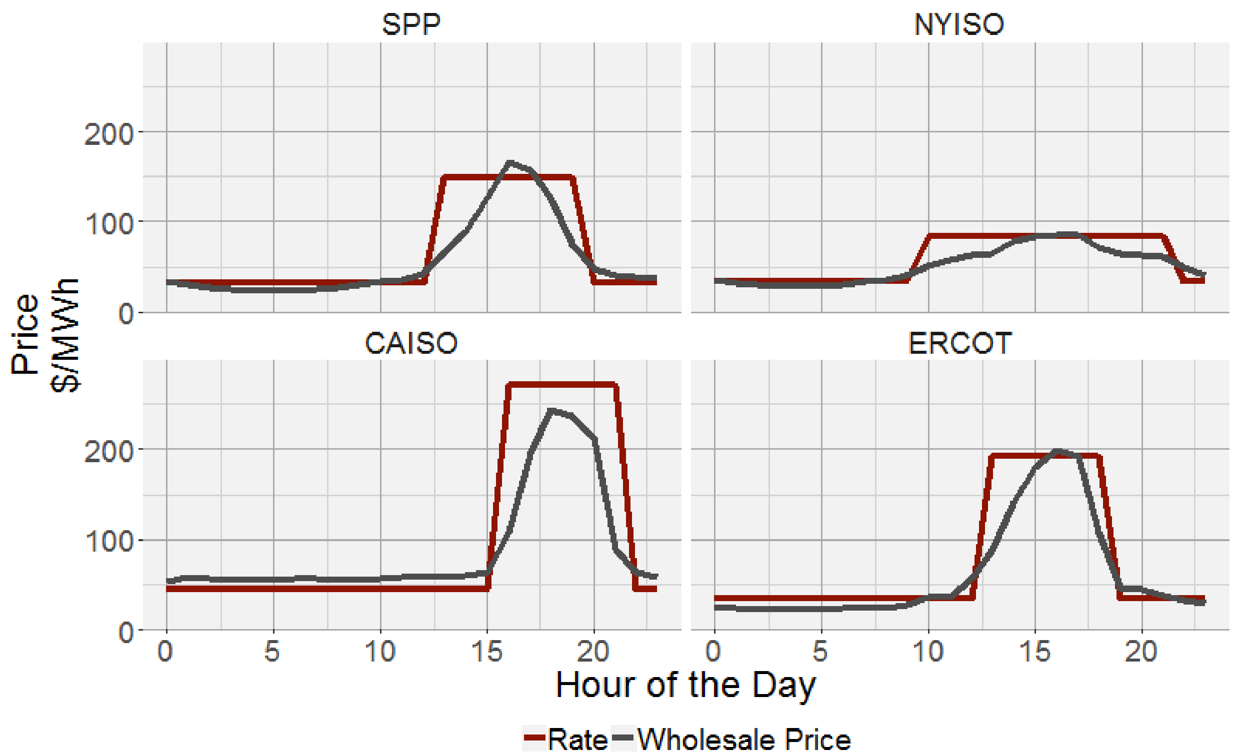

Figure 20. Low VRE two-period TOU rates in summer months in each market region

We expect time-varying rates to create greater economic value than flat rates. Figure 21 demonstrates in a low VRE scenario that the amount of DWL per megawatt-hour declines with greater time-differentiation of rate structures. Though, as explained earlier, rate designers face trade-offs between simple rate structures that customers can easily understand and complex rate structures that encourage efficient consumption of electricity. In a low VRE scenario, the improvements in economic efficiency that time-based rates offer in comparison to flat rates are small, about $2/MWh in most regions. As such the limited gains in economic efficiency may not fully justify their deployment, given increased rate complexity and losses in Bonbright's principle of rate simplicity. Though more sophisticated than TOU, CPP rates reduce DWL by another $1/MWh to just a few cents per MWh.

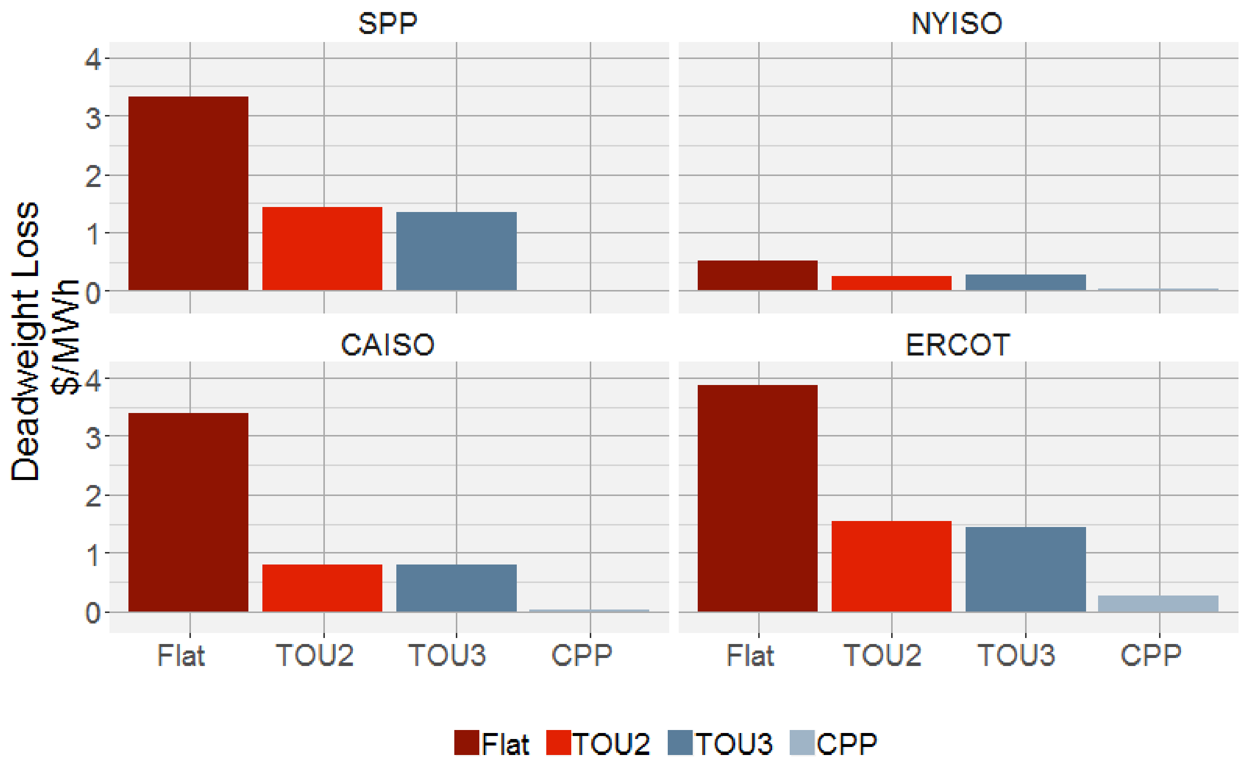

Figure 21. Economic performance of rate structures in a low VRE scenario

Deadweight Loss Increases in a High VRE Scenario if Rates Do Not Change

In the second step of our analysis, we test the performance of the parameters chosen for a low VRE scenario in a high VRE scenario. We find flat structures can generate a three-fold increase in DWL in a high VRE scenario. We also find changes in wholesale price patterns (*peak-shifting*) can cause time-based rates to produce significant increases in DWL if peak windows are not updated in a high VRE scenario.

Flat Rates Cannot Capture Increased Price Volatility

For a decision-maker facing competing rate design goals, a flat rate may create a tolerable amount of economic loss in a low VRE scenario. However, we find high VRE penetrations will cause simplified rate structures to no longer achieve the same levels of economic efficiency.

Figure 22 shows the increase in DWL from a flat retail rate structure in a low VRE scenario compared to each high VRE penetration level. In each scenario, we find DWL increases relative to the low VRE scenario due to increased wholesale price volatility. The greatest increases in DWL occur in a high solar scenario where DWL increases threefold on average. In ERCOT, DWL from a flat rate can increase more than fivefold, from $4 per MWh to $22 per MWh, driven both by an increased frequency of very high scarcity prices and a ubiquity of hours with very low wholesale prices during the middle of the day that occur less often in the other ISOs with stronger interconnections to neighboring regions. Given that a majority of U.S. customers are enrolled on flat rates, high VRE scenarios have the potential to create substantial economic loss to society if decision-makers do not transition retail pricing away from flat rates.

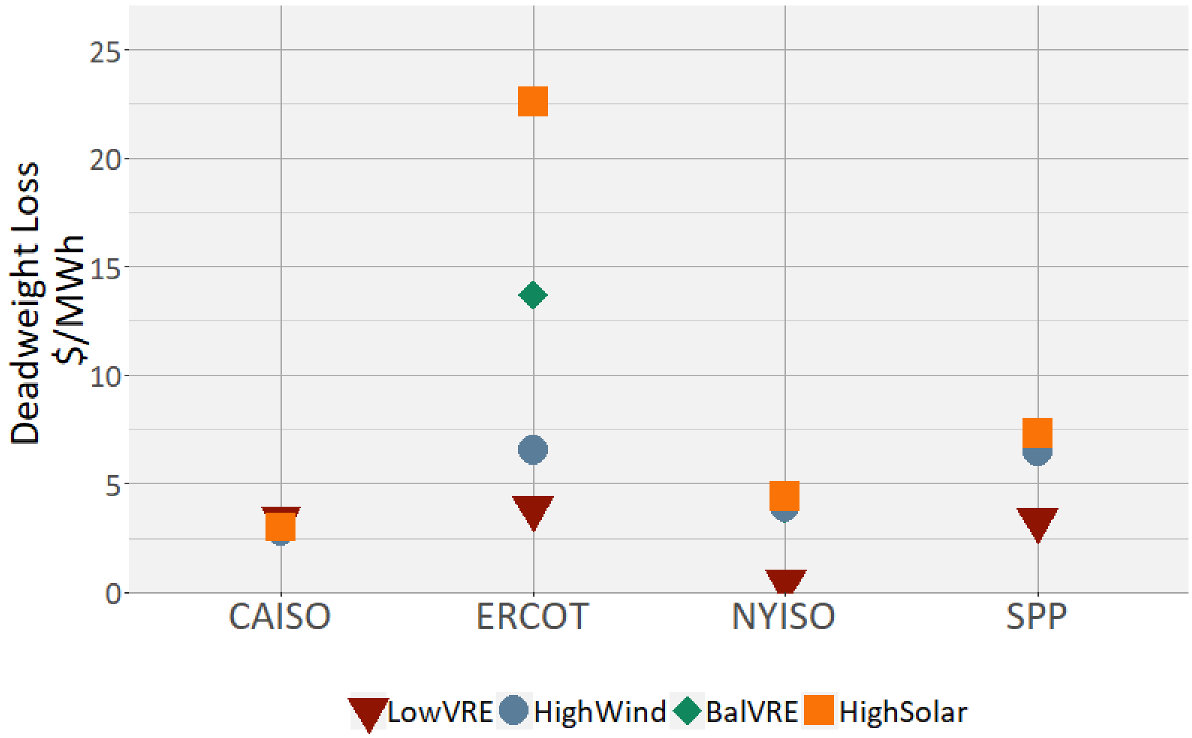

Figure 22. Economic performance of a flat rate structure in low VRE and high VRE scenarios

In CAISO, flat rates perform very similarly in both a low and a high VRE scenario. The result is counterintuitive because we expect higher penetration levels of VRE to produce greater price variability and therefore weaken the performance of flat rates. We attribute the very modest improvement in efficiency in CAISO to falling wholesale prices which lower peak prices relative to a low VRE scenario. In contrast, peak prices increase in the other three market regions.

Stable Time-Based Rates Do Not Reflect Shifting Wholesale Peaks

While flat rates will lead to a loss of economic efficiency in a high VRE scenario, time-based rates will also fail to perform efficiently if tariff design is not updated. High penetrations of VRE will drive the distribution of peak prices to shift into the late afternoon and early evening hours (Seel, Mills, and Wiser 2018). This wholesale peak-shifting implies that retail rates with a time-varying component need to shift in tandem.

In Figure 23, the red dashed line represents the two-period TOU rate in the NYISO market region that minimizes deadweight loss in a low VRE scenario (see Figure 20). We also overlay the low VRE rate with average hourly wholesale prices for each of the high VRE penetration scenarios. Figure 23 shows two shortcomings of the low VRE time-based rate in a high VRE scenario. First, the peak period is too lengthy and covers hours of low-priced electricity during the middle of the day. Second, the ratio between the peak period and the off-peak period is too modest. High VRE scenarios require greater ramping in the late afternoon and early evening as solar resources come offline. Time-varying rates may mitigate some of these greater ramping needs with higher peak-to-off-peak price differentials if price responsive loads reduce their energy consumption during the evening hours.

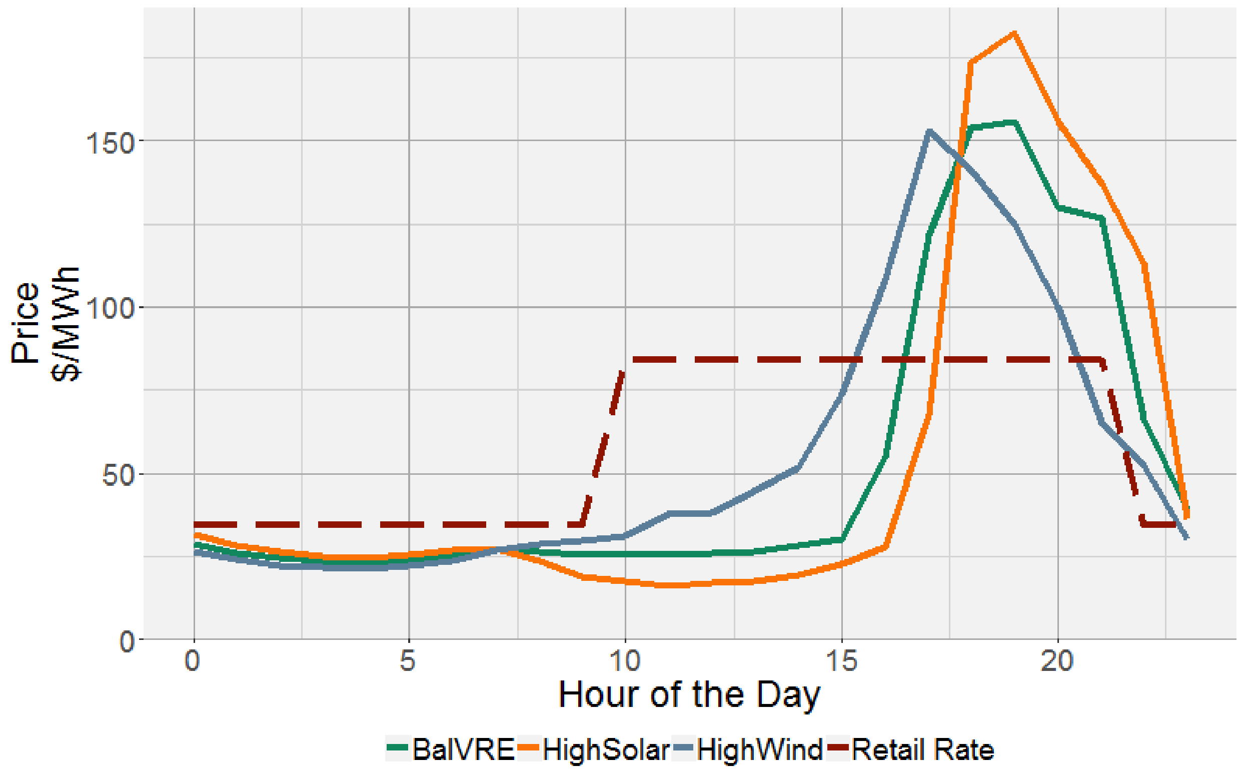

Figure 23. A low VRE two-period TOU rate in NYISO compared to high VRE prices

Our analysis finds that peak-shifting can drive substantial increases in deadweight loss if time-based rates are not updated. The magnitude of changes ranges widely, but can be as high as 15 times under TOU rates and even more for CPP rates. Time-based rates designed for low solar levels perform worse in scenarios with high solar penetrations due to the greater peak-shifting effect solar production has on diurnal price profiles compared to wind production.

Figure 24 shows that the impacts of peak-shifting are muted in CAISO. We attribute this lessened impact to the already high levels of solar penetration in the low VRE scenario (at 2016 levels of 14 percent). Additional VRE penetration in CAISO does not shift the timing of the peak period between scenarios substantially further. ERCOT, in contrast, currently features high penetrations of wind generation. We see significant increases in deadweight loss in the high solar scenario in ERCOT because peak periods would shift significantly compared to the low VRE scenario.

Not shown in Figure 24 are the changes in DWL for CPP rates. Limited price differentials and mistimed peak periods also cause low VRE CPP programs to perform worse in a high VRE scenario, but the impacts are greatly amplified due to the magnitude of event-day prices. Whereas DWL may increase by 15 times for TOU rates, it increases by up to 60 times for CPP. Restricting the number of CPP event days also increases DWL, which we discuss in the following section.

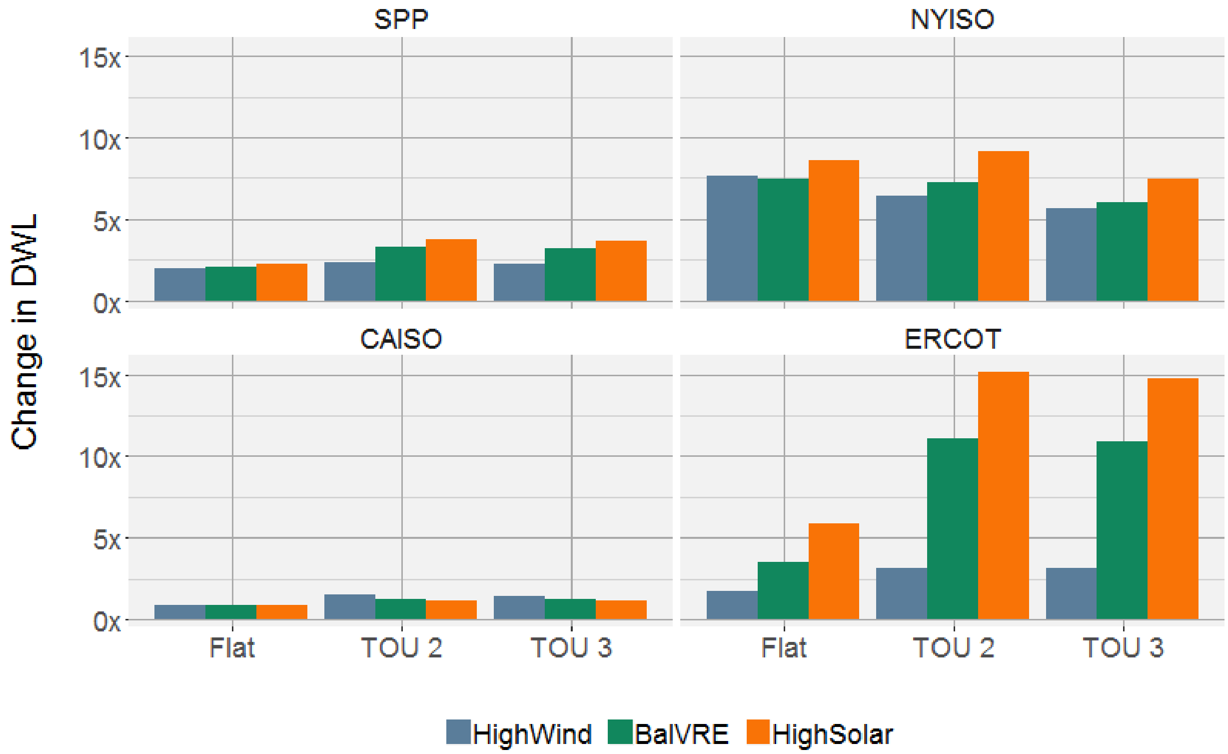

Figure 24. Economic performance of low VRE rates in a high VRE scenario

Time-Varying Rates Need to Change in a High VRE Scenario

To maintain the economic advantages of time-based rates in a high VRE scenario, their attributes need to be updated. We highlight the benefits of a super-off peak period and expanded use of CPP programs. In addition to these changes, decision-makers could consider greater peak to off-peak price differentials.

Cheaper Super-Off Peak Period

Two of the main drivers of inefficient rate design are rates that charge too high a price when costs are low and rates that charge too low a price when costs are high. In the non-summer months, we see an increase in near-zero cost events during periods of excess renewable generation and low demand from customers. To maximize economic value to customers, retail rates could mirror these near-zero cost events by instituting a super-off peak period.

Low-priced super-off peak periods allow customers to shift demand from hours when electricity is expensive to supply to hours when renewable resources may require curtailment. We find that efficient TOU rates in a high solar scenario will include super-off-peak periods with price differentials as low as 0.4 to 1 compared to the off-peak period. We find the super off-peak effects to be the strongest in the high solar scenarios in CAISO, followed by SPP (see Figure 25) and ERCOT. In contrast, we find that the most efficient three-period TOU rate in a low VRE scenario can be achieved with a much more moderate super-off peak period featuring only 0.8-to-1 to 0.95-to-1 ratios during the non-summer months.

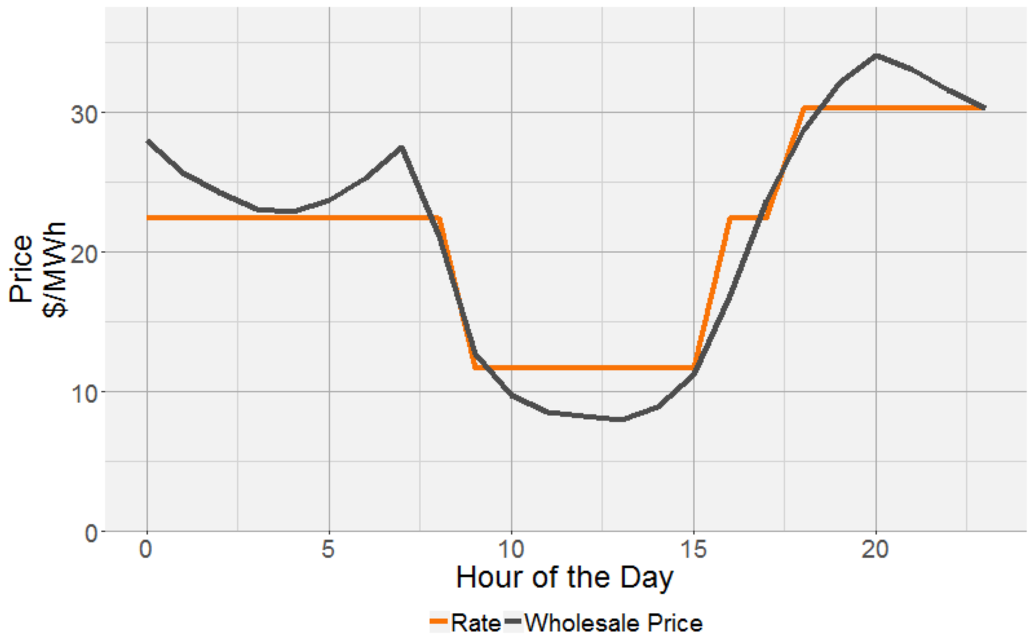

Figure 25. A high solar three-period TOU rate in SPP compared to high solar prices

More CPP Event Days

As seen in **Error! Reference source not found.**, a CPP program layered with a three-period TOU r ate is the most efficient rate design that we evaluate in our analysis. By charging high prices during times of exceptional demand, CPP rates encourage customers to cut back on consumption they do not value as highly as the cost it imposes on the grid. Lower rates during all other hours typically result in overall bill savings for the customers. However, the number of CPP event days that an operator can call is usually set in advance, and their limited use may pose significant hurdles to efficient retail pricing. These limits, usually about fifteen event days per year, already present a barrier to effective use of CPP in a low VRE scenario (Borenstein 2017). On average across the four market regions, we find that an operator may call 23 CPP event days per year in a low VRE scenario.[24] If operators are not allowed to expand the number of event days, the efficiency of a CPP program will be even more limited in a high VRE scenario.

Due to increased price volatility, we find the optimal number of CPP event days could increase strongly with growing VRE penetrations, as shown in **Error! Reference source not found.**. On a verage they grow by approximately 50 percent to 34 event days in a balanced VRE scenario relative to 23 days in the low VRE scenario. We further find that an operator could call as many as 46 event days in a high solar scenario in ERCOT as the 100 top net-load hours with their high

[24] We arrive at the optimal number of CPP event days by determining the number of days that the top 100 net-load hours fall on, though results may vary if we choose 50 or 200 hours.

prices are now dispersed over more days. This represents approximately one-third of all days from June 1 to September 30. With such an increased requirement of CPP event days, rate designers may consider more complex rate structures like Oklahoma Gas and Electric's variable-peak pricing rate.

Table 2. Distribution of CPP event days in low and high VRE scenarios

	LowVRE	High Wind		Balanced		High Solar	
ISO	Days	Days	Δ	Days	Δ	Days	Δ
CAISO	30	30	*0%*	33	*10%*	36	*20%*
ERCOT	22	25	*14%*	41	*86%*	46	*109%*
NYISO	15	22	*47%*	27	*80%*	26	*73%*
SPP	24	28	*17%*	34	*42%*	38	*58%*
Average	**23**	**26**	***15%***	**34**	***48%***	**37**	***60%***

Time-Differentiated Tariffs Are More Valuable in a High VRE Scenario

The competing principles of rate design require decision-makers to balance economic efficiency against other important objectives like simplicity and customer acceptance. A key result of our analysis is that the marginal efficiency gain from time-differentiated tariffs rises sharply with growing wind and solar penetrations compared to a low VRE scenario, as highlighted in Figure 26. At the same time it becomes much more costly to maintain a simplified rate structure in a high VRE scenario.

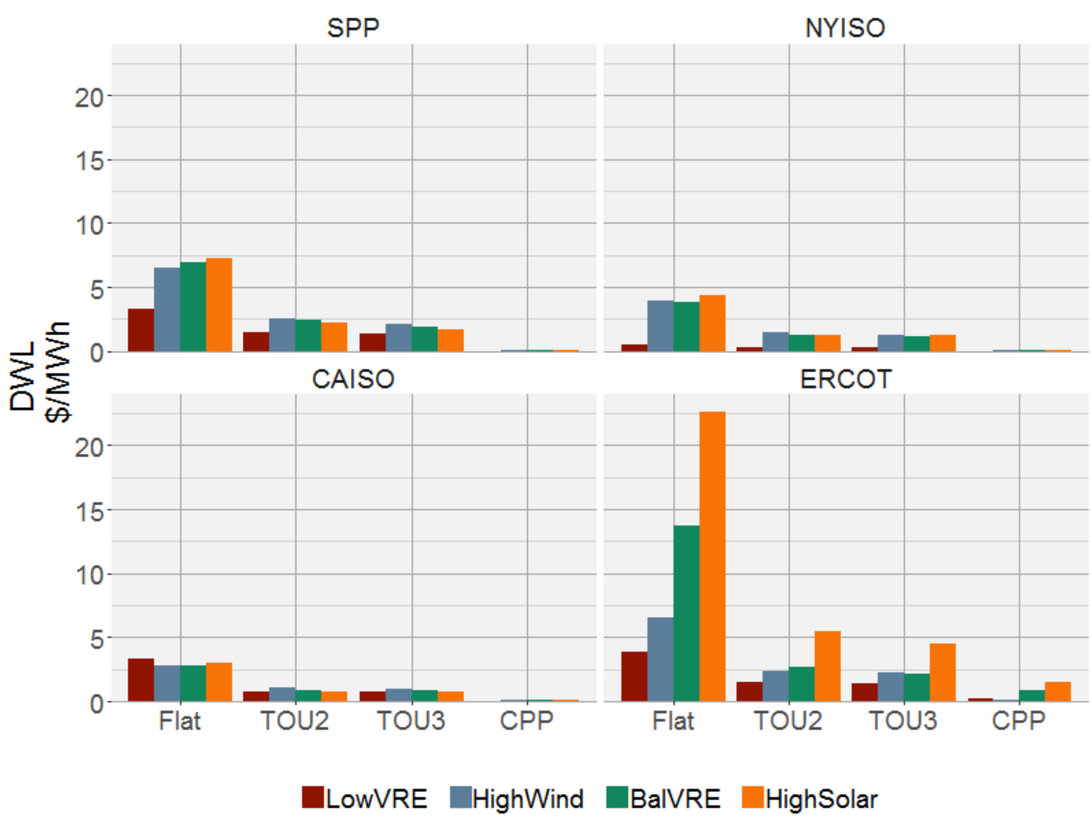

Figure 26. Economic performance of optimized rate structures in low and high VRE scenarios

We find in a scenario with low VRE shares that TOU rates provide about a 60 percent improvement in economic efficiency compared to flat rates. In high VRE scenarios this efficiency gain grows on average to 70 percent. Our results vary by region: We find the greatest efficiency increase in NYISO, where time-based rates outperform flat rates by 72 percent in the high solar scenario compared to only 47 percent in a low VRE scenario.

While static TOU rates provide stronger improvements in economic efficiency in high VRE scenarios, CPP programs provide similar efficiency gains in low and high VRE scenarios. We find that a CPP program combined with a three-period TOU can improve deadweight loss by about 95 percent in both low and high VRE scenarios. CPP programs present greater complexity to customers, but the efficiency gains associated with them are high independent of possible penetration levels of VRE. However, this holds true only if grid operators are less constrained in the number of event days they can call.

4.4 Discussion

Our quantitative assessment shows the importance of rethinking rate design in the context of high VRE scenarios. Foremost, decision-makers may want to prioritize time-varying and critical-peak rate structures. The trade-off between other valuable rate design principles and economic efficiency may justify flat rate structures in a low VRE scenario. However, we find the lost economic value to society caused by flat rate structures will increase by more than a factor of three in high VRE scenarios.

Our analysis estimates that if all customers were enrolled on a flat rate, the deadweight losses would increase in high VRE scenarios relative to the low VRE scenario by an additional $4.6 billion in ERCOT, $1.1 billion in SPP, and $600 million in NYISO. In CAISO this effect is negligible due to reduced price volatility and lower peak prices. These large reductions in economic efficiency of flat rates could motivate rate makers to examine more efficient time-varying rates as a promising alternative.

However, changing diurnal price profiles also necessitate redesigning existing TOU rates. Because tariffs are typically designed using historical data and are updated in proceedings that last several years, decision-makers may consider how increasing penetration levels of VRE will affect the peak window of time-varying rate offerings. Our analysis concludes that with growing solar penetrations the most efficient TOU rates will feature peak periods that are shifted to the evening hours and include the addition of a super-off peak period during the middle of the day.

Our analysis also makes the case for the expansion of CPP programs. Of the rate structures investigated in this analysis, a CPP program combined with a three-period TOU rate offers by far the best mechanism for maximizing economic value to customers, no matter the scenario of VRE penetration. On average across each market and each VRE scenario, a TOU plus CPP rate produces only 25 cents of DWL per megawatt-hour.[25] In contrast, a flat rate produces $6 per megawatt-hour across each market region and scenario.

For CPP programs to be effective, the number of CPP events called during a year may need to increase above the number that most programs allow to be called today. This finding is important because CPP events today are mostly limited to 10 to 20 days per year out of fears that customers will not be able to respond to dynamic pricing. By limiting the availability of CPP events in a high VRE scenario, our findings suggest tariffs will be subject to greater levels of economic inefficiency.

4.5 Conclusion

While we do not advocate for a "perfect" rate design, we have shown that the impacts of high penetration levels of VRE suggest that decision-makers may want to consider changes to existing retail rates. Benefits of efficient retail pricing are far-ranging and have important implications across the electricity sector. For example, aligning retail rates more closely with marginal cost can increase overall demand responsiveness to varying system needs and accelerate the beneficial electrification of heating needs in buildings or the adoption of electric vehicles. In turn this technology adoption may enable higher customer price elasticities and thereby larger potential efficiency gains. More transparent retail rates may also reduce costly investments in peak generation capacity and facilitate the integration of higher shares of variable renewables. In addition, extensive industry experience shows that time-differentiated tariffs can reduce customer's bills.

Our analysis is limited by our level of granularity with respect to customer class. Further research is needed to assess how residential, commercial, and industrial customers might be able to capture more economic value from rate design in a high VRE scenario. Similarly, further analysis would benefit from considering the impacts of T&D costs on rates in various future VRE scenarios.

Given that rate design experts value other important design principles like customer acceptance, decision-makers might consider beginning the transition to greater deployments of time-varying rates quickly and rolling it out gradually. The speed of the required rate transition will depend on the speed of potential adoption of variable renewables in a given region. However, our findings show that apparent tipping points of economic performance already have been reached at CAISO's 2016 VRE penetration levels (7 percent wind and 14 percent solar); they do not manifest only at much higher renewable shares.

[25] Our analysis assumes perfect foresight of CPP events, though weather forecasts make predicting event days imprecise. In addition, our analysis only considers 100 percent adoption of CPP rates, which may be unrealistic given that only roughly 60 percent of U.S. customers have access to smart-metering technology. Smart meter deployment may increase over the next two decades, during which time nearly all remaining analog meters will be replaced at the end of their operating lifetime.

5 Conclusions

High shares of variable renewable energy (VRE) such as wind and solar will fundamentally impact wholesale electricity price dynamics and make them meaningfully different from the traditional wholesale electricity price patterns with low renewable energy penetrations. Due to these elemental changes, electric-sector decision making may need to evolve, depending on the relative growth of wind and solar resources on the grid, in order to continue to achieve the intended objectives. Therefore, electric-sector decisions that continue to be based on system assumptions that reflect little VRE penetration may not achieve the desired outcomes in a scenario with high wind and solar shares.

The purpose of this scoping report was to describe analytical methods for evaluating the sensitivity of demand-side decisions to different levels of VRE penetration and to illustrate the susceptibility of some paradigmatic demand-side decisions to changes associated with high VRE growth. Stakeholders can leverage our results to inform a variety of decision types, and evaluate whether long-lasting decisions are robust over a range of scenarios with varying VRE penetrations.

This scoping report evaluated the impacts of changing patterns of peak system needs on the benefits of demand reductions by examining the altered value of different energy efficiency (EE) measures that are often combined into portfolios by an EE program designer. Similarly we investigated new opportunities that may arise from very low priced wholesale electricity for large energy consumers. We appraised the value of new process investments (e.g., hydrogen production and other generalized electro-commodities), estimated the benefits of increased process flexibility that may use electricity as a process-input in addition to traditional fossil fuels (e.g., district energy systems), and showcased the varying value of new product storage investments (such as reservoir extensions at a desalination plant).

Finally, many decentralized decision-makers and end-use customers are not directly exposed to wholesale electricity prices but instead receive price signals from their retail electricity rates. We analyzed how economically efficient retail rates may need to become more dynamic and evolve in their application and definition of time-of-use tariffs and critical peak-pricing events as wind and solar shares increase.

The following sections summarize key results for each of the three areas of interest and identify suggested areas for future research.

5.1 Energy Efficiency Valuation

Energy efficiency measures and programs continue to deliver consistent, measurable benefits. However, given the possible shifts to more dynamic price patterns that will be spurred by increased VRE deployment, EE program designers may want to reevaluate each EE measure or program to determine if it will provide the same or better benefits under future scenarios.

Some key findings:

- Forward-looking scenario analyses that leverage time-dependent valuation approaches can assist EE decision-makers by providing useful information about resource trade-offs under high VRE scenarios.
- Both the absolute values and relative ranking of EE measures will change with higher VRE penetrations.
- High wind scenarios can increase irregular hourly price volatility but can moderate average diurnal price profiles over longer periods—consequently, they may flatten the value differences between EE measures.
- High solar scenarios have a strong effect on diurnal price profiles, and so can lead to stronger value differences between EE measures. This finding emphasizes the importance of choosing EE measures that are appropriate to each situation, as well as the advantage of VRE-specific scenario analyses.
- In high VRE scenarios, residential EE upgrades that lower evening consumption seem to deliver higher value savings than office EE upgrades that provide daytime savings; those residential EE upgrades could be targeted in future program design.

Future research could evaluate a broader set of EE measures and leverage more robust empirical and location-specific EE saving shape data. Expanding the scenario analysis to assess the implications of different EE uptake scenarios and include additional value streams, as well as adding consideration of EE measure costs, will greatly enhance the usefulness of these analyses.

5.2 Opportunities for Large Energy Consumers

Large energy consumers can benefit from changing electricity price dynamics and increased frequencies of very low price events if they can access wholesale electricity markets (or have retail rates that reflect the new price patterns) and if they can substitute electricity for other energy inputs in their production processes. Given the long design life of many industrial capital investments, decision-makers may want to evaluate closely whether their typical investment assumptions still lead to cost-effective outcomes in a high VRE world.

Some key findings:

- Large energy consumers who will benefit most from periods of low electricity prices in high VRE scenarios are those that:
    - have energy-intensive processes such that energy costs are high relative to the capital costs of production equipment (e.g., electro-commodities).
    - can effectively decouple commodity production from demand by increasing intermediate or final product storage capacity.
    - can add invest in the capability to switch between fuels and electricity during periods of low electricity prices.

To achieve the granularity of results necessary to guide investment decisions, each potential end use application will require its own analysis. Further research might explore, for example:

- how relative R&D investment requirements to reduce either the capital cost of relevant equipment or yield higher process efficiencies compare with the changing cost-reductions in high VRE scenarios.
- the potential for electricity to provide higher temperature heat for industrial applications.
- how industrial production schedules can be modified to increase flexibility in their electricity consumption in response to more dynamic electricity prices.
- how low VRE prices would affect location decisions about new production plant investments, technology choices within a given industry, and electricity market dynamics if demand grows during low cost periods.

5.3 Retail Rate Design

This study showed that more dynamic retail rates will have far-reaching benefits under high VRE scenarios that have increased wholesale price variability. Deciding whether to shift to more dynamic rates requires evaluating the tradeoff between increases in economic efficiency and increases in rate complexity.

Some key findings:

- Aligning retail rates more closely with marginal cost can increase overall demand responsiveness to varying system needs.
- More dynamic retail electricity rates have lower economic losses than flat rates, and their relative benefit increases with higher VRE penetrations. This change justifies a more serious deliberation of complex versus simple rate structures.
- Growing wind and especially solar shares also have strong impacts on the best definition of peak versus off-peak periods that are used in time-of-use periods. High versus low price periods defined for a low VRE environment can lead to even worse outcomes than maintaining flat rates when applied without changes to a high VRE environment. In contrast, appropriately calibrated retail rates that feature, for example, a new super-off peak period in the middle of the day in a high solar scenario, can bring large efficiency gains.

Further research might assess how residential, commercial, and industrial customers might capture more economic value from rate design in a high VRE scenario. Such research also might consider impacts of T&D costs on rates in various future VRE scenarios.

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Appendix A. Energy Efficiency Valuation

Figure A-1 illustrates the winter and summer load shapes of location-independent end-use loads.

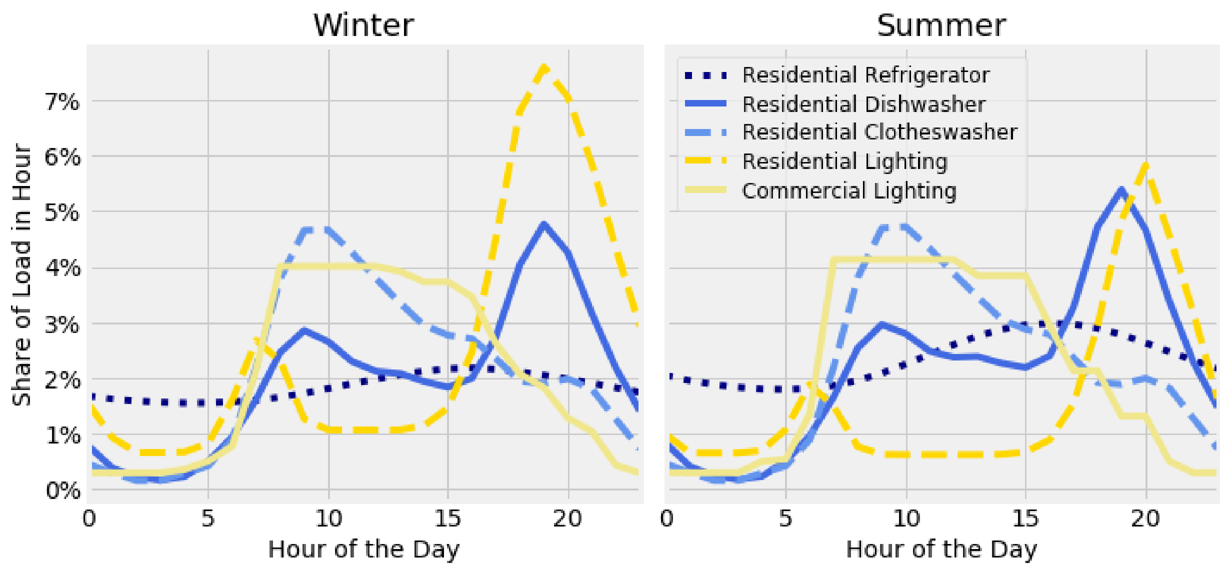

Figure A-1. Load shapes by season that are held constant across ISOs

Loads varying by location are illustrated in Figure A-2 below. We leverage NREL simulations of building load components based on TMY3 weather data as reported by Wilson (2014). HVAC loads in commercial buildings include climate-specific cooling, heating, and fan load components in all eight cities that we assess. HVAC loads in residential buildings differ however: In all cities except Dallas heating energy is assumed to be provided by a gas furnace, and the HVAC electricity consumption only represents fan loads to move heated air from the gas furnace throughout the house and cooling loads to run the AC. San Francisco is the only location with no cooling loads—the residential HVAC electric load there only represents the fan load that is coincident with usage of the gas furnace.

The absolute magnitude of HVAC electricity consumption differs accordingly between each of our eight locations. As we do not evaluate the overall revenue of efficiency savings but focus on changes in the hourly valuation of energy efficiency, we normalize all HVAC loads equivalent to 1 MWh of annual consumption, just as we did with the other load shapes depicted above.

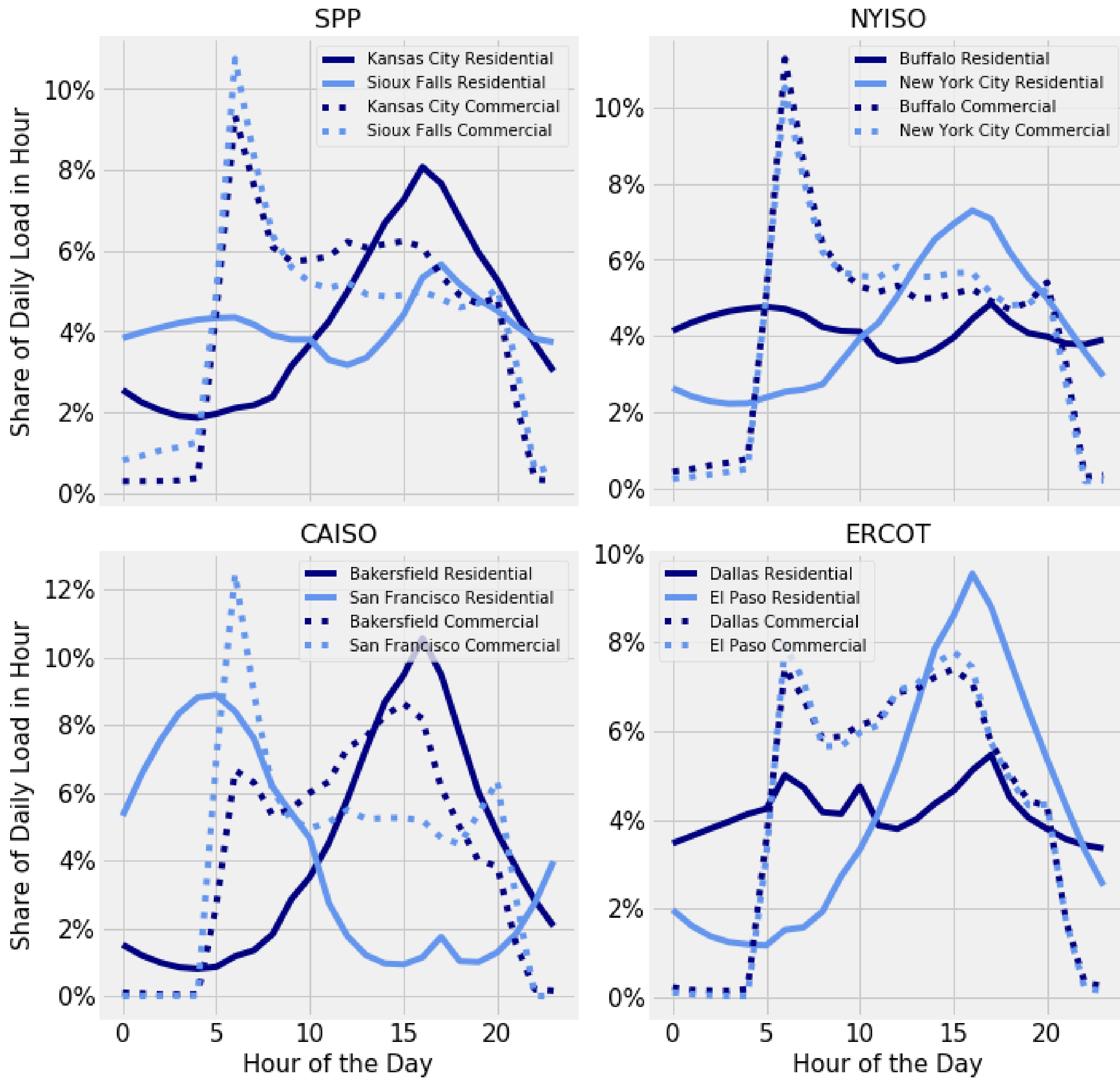

Figure A-2. Annual average HVAC load shapes by location

Appendix B. Opportunities for Large Energy Consumers

B.1. Assumptions for quantitative analysis and sensitivity results

This section contains figures and tables describing numerical assumptions built into our estimates of levelized production costs. Values for the parameters are determined from a combination of literature reviews and interviews with experts. As explained in the body of the main report, the objective of our analysis is not to derive detailed cost estimates of each industrial end-use application but rather to identify directional changes in VRE scenarios. Nevertheless, the selection of reasonable technology and cost parameters is essential to our analysis. We select conservative assumptions when available, and select current technology and cost parameters as opposed to forecasted values in 2030 unless stated otherwise. Sensitivity analyses for influential parameters are provided either in the main report or here in the appendix.

Hydrogen Production

The hydrogen production cost results in the main report assume capital costs of $650/kW for the electrolyzer (fully burdened, equivalent to uninstalled costs of $400/kW), see Table B-1.. Such costs seem not yet to be widely available to prospective buyers in 2019 and assume further capital cost reductions from current prices. To explore impacts of VRE-induced wholesale price changes over a range of electrolyzer costs, we include below sensitivity results of levelized production costs and optimal electrolyzer utilization rates for uninstalled electrolyzer costs for $900/kW (similar to current prices), as well as ambitious uninstalled cost targets of $200/kW and $100/kW (Figure B-1 though Figure B-6). The derivation of fully burdened costs is based on Saur, Ramsden, James, Colella, & Penev (2018a, 2018b).

Table B-1. Hydrogen production assumptions

Assumption	Units	Value
Electrolyzer capital cost (uninstalled)	$/kW	400 (sensitivities: 900, 200, 100)
Electrolyzer capital cost (fully burdened)	$/kW	650 (sensitivities: 1500, 325, 165)
Electrolyzer efficiency	%	70
Electrolyzer maintenance cost	%	4% of capital costs
Electrolyzer lifetime	Years	25
Electrolyzer stack lifetime	Hours	60,000
Electrolyzer stack replacement cost	%	25% of capital costs
Discount rate	%	6

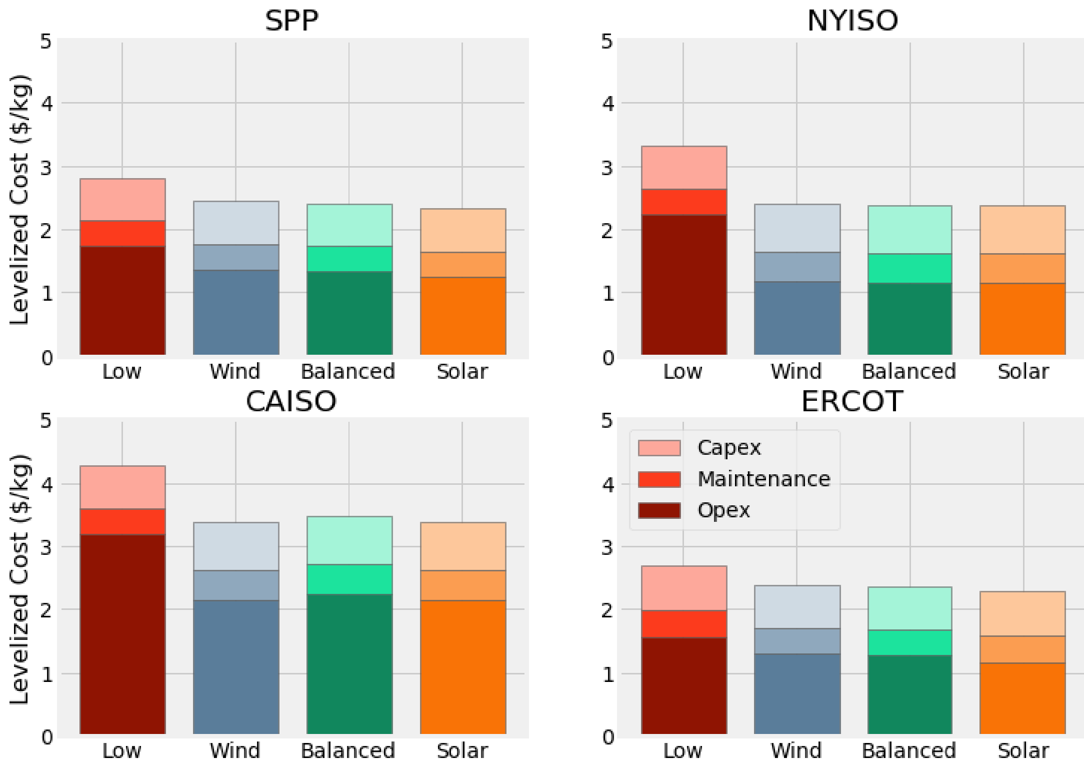

Figure B-1. Levelized hydrogen production costs across scenarios at $900/kW (1500 fully burdened)

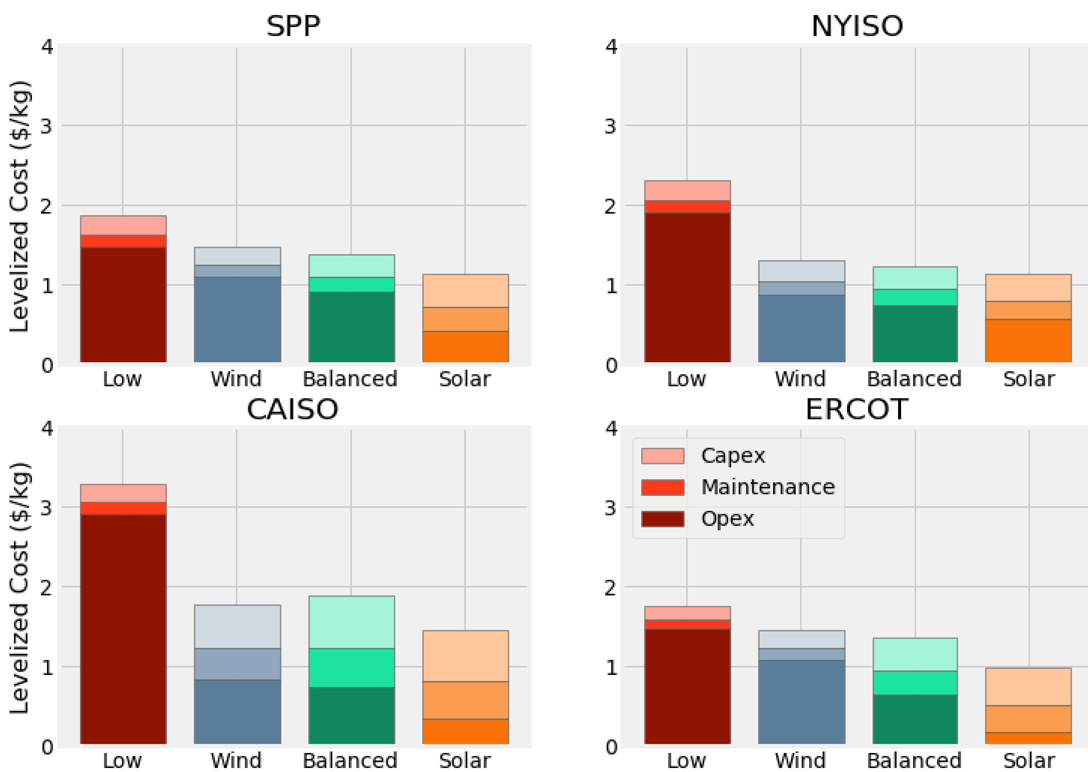

Figure B-2. Levelized hydrogen production costs across scenarios at $200/kW (325 fully burdened)

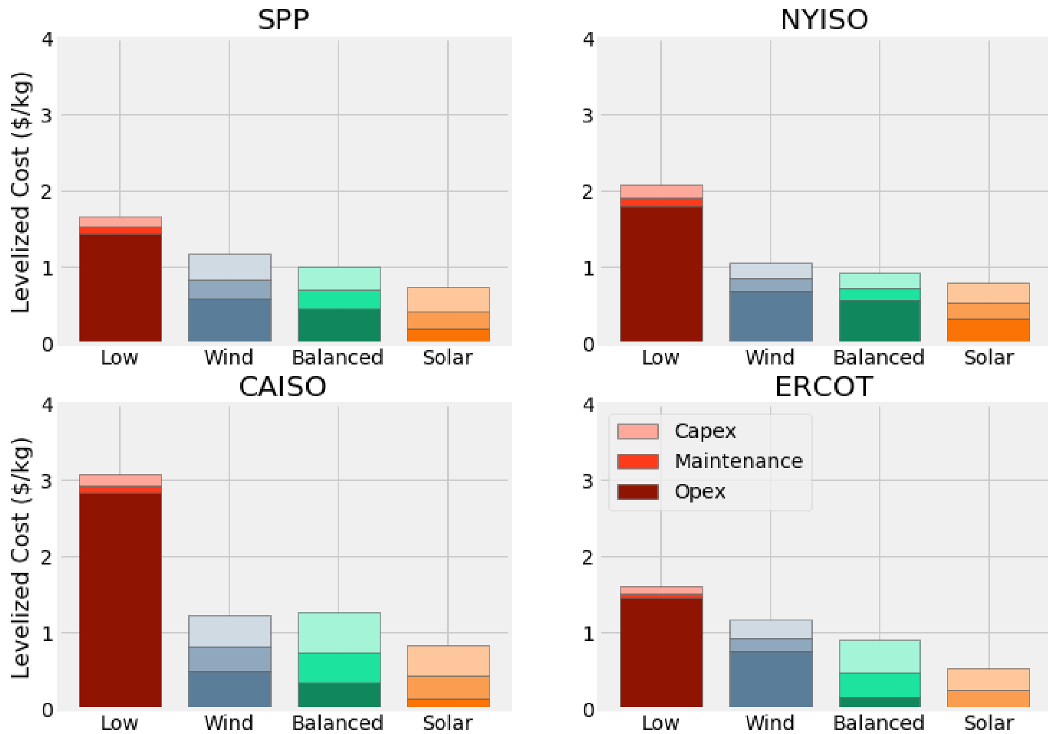

Figure B-3. Levelized hydrogen production costs across scenarios at $100/kW (165 fully burdened)

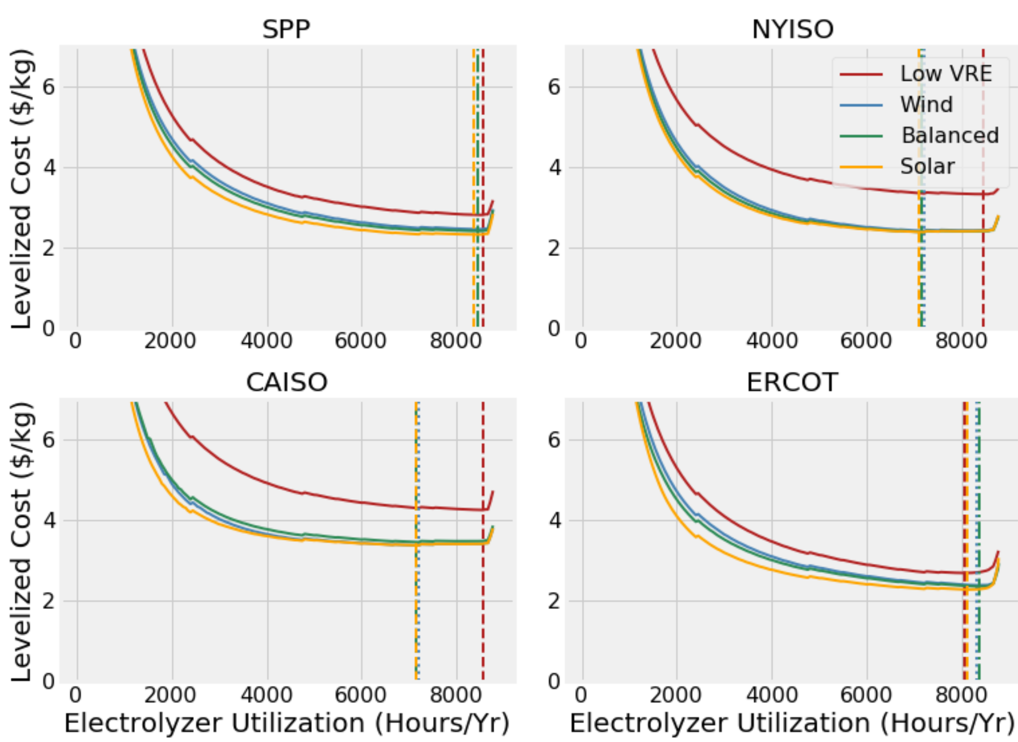

Figure B-4. Cost minimizing utilization rates of the electrolyzer at $900/kW (1500 fully burdened)

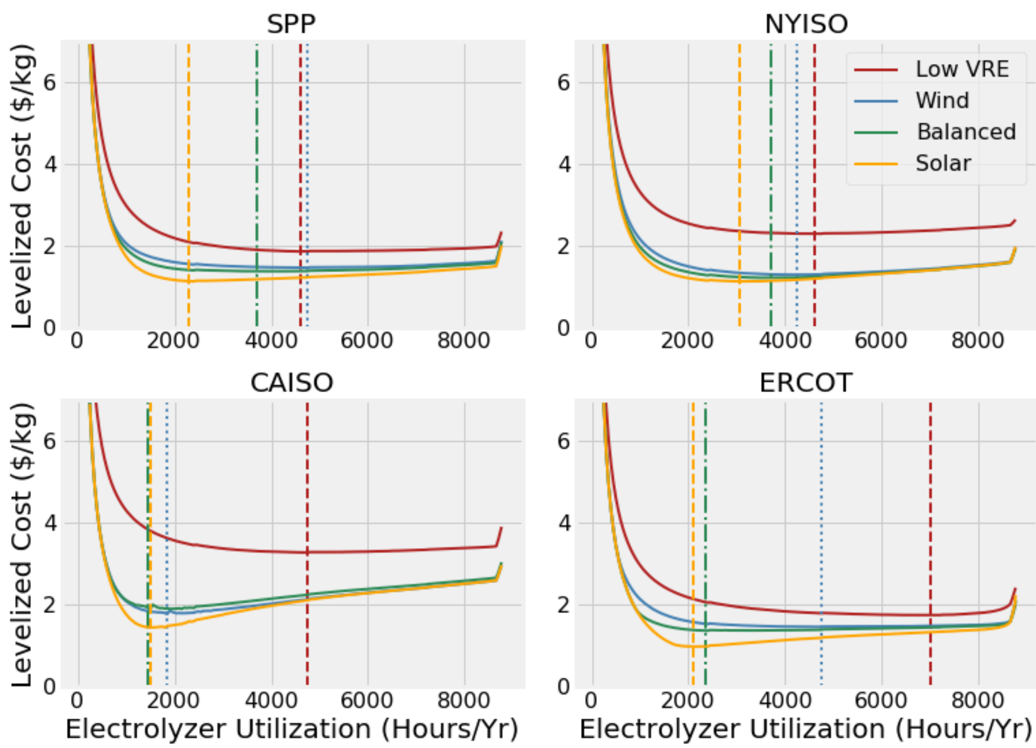

Figure B-5. Cost minimizing utilization rates of the electrolyzer at $200/kW (325 fully burdened)

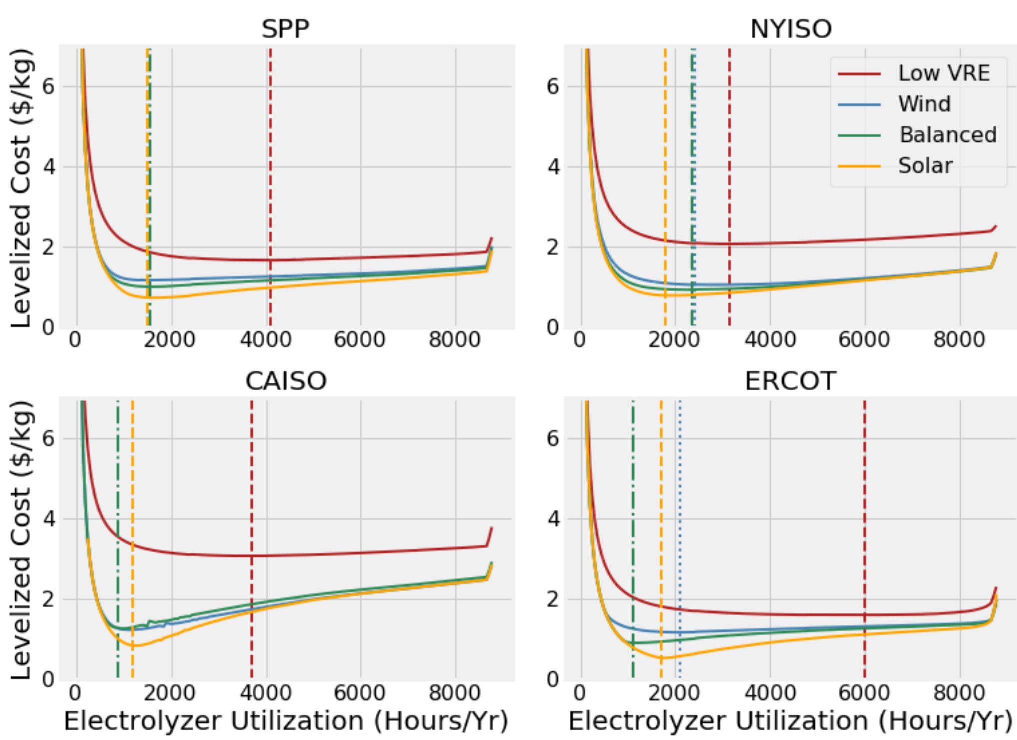

Figure B-6. Cost minimizing utilization rates of the electrolyzer at $100/kW (165 fully burdened)

Desalination

Table B-2. Desalination assumptions

Assumption	Units	Value
Desalination plant capital cost	$ million	90
Desalination plant capacity	Mgd	27.5
Average desalination plant efficiency	kWh/kgal	2.4
Desalination plant maintenance cost	% of capital cost	33
Desalination plant lifetime	Years	25
Reservoir cost	$/acre-foot	200
Reservoir lifetime	Years	40

District Energy Systems

Table B-3. District energy assumptions for college-campuses

Assumption	Units	Value
Cogeneration capital cost	$/kW	800
Cogeneration electric generation efficiency	%	35
Cogeneration steam efficiency	%	40
Cogeneration total efficiency	%	75
Cogeneration maintenance cost	% of capital cost	4
Cogeneration lifetime	Years	25
Gas boiler capital cost	$/kW	120
Gas boiler steam efficiency	%	70
Gas boiler maintenance cost	% of capital cost	4
Gas boiler lifetime	Years	25
Reserve margin met by gas boiler	% of peak demand	10
Electric heat pump capital cost	$/kW	800
Electric heat pump efficiency (COP) college-scale	%	500
Electric heat pump maintenance cost	% of capital cost	4
Electric heat pump lifetime	Years	25
Electric heat pump capacity in hybrid college-scale case	MW	20
College-scale simulated secondary-school buildings	Number of buildings	25
College-scale simulated mid-rise apartment buildings	Number of buildings	10
Carbon price NYISO	$/ton	24
Carbon price CAISO	$/ton	50
Discount rate	%	6

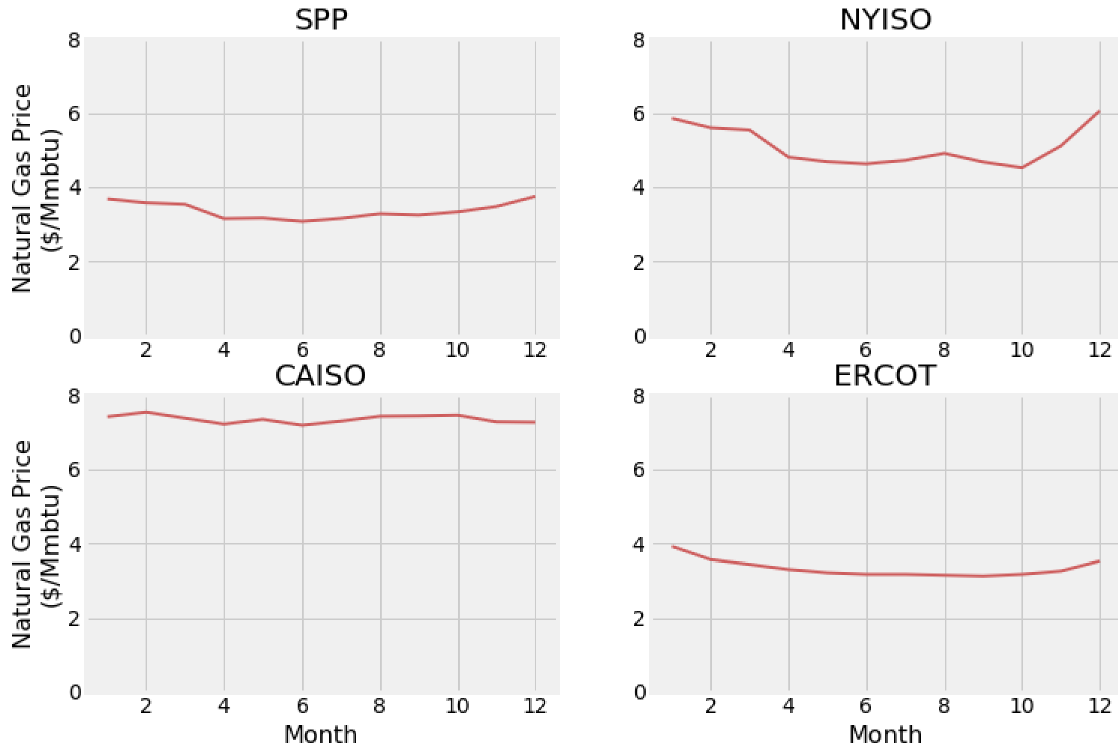

Figure B-7. Natural gas price assumption in a DE analysis

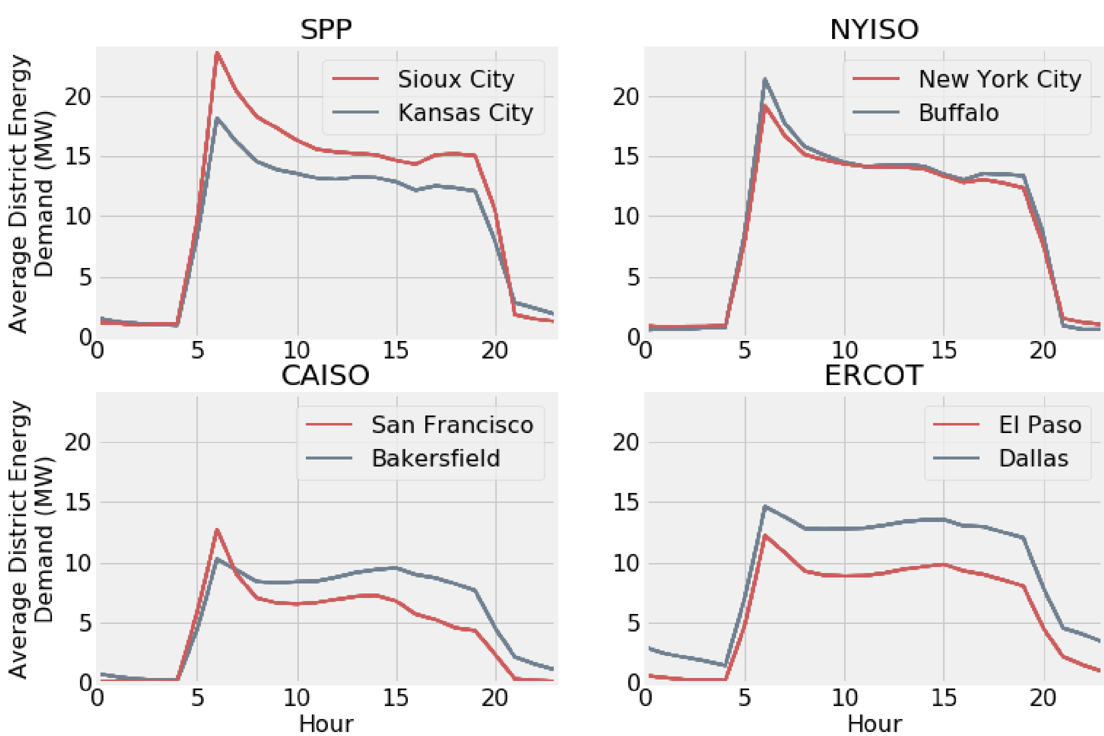

Figure B-8. Simulated hourly district energy demand for heating and cooling for the college campus system

B.2. Case Study of Fuel Flexibility in ConEdison's District Energy System

Assumptions

This case study examines opportunities for fuel-switching for Consolidated Edison's (ConEd) DE system in Manhattan, the largest DE system in the world. We follow the assumptions of the stylized college DE system unless otherwise noted. We interviewed ConEd for this report and used reported ConEd data when possible.

The DE system in Manhattan provides approximately 20,000 million pounds (MMlb) of steam per year to 1,622 large customers for heating and cooling purposes (Con Edison 2012; 2019). The typical maximum hourly demand on the system, which occurs in the winter, is approximately 8.1 MMlb. In the summer months, maximum demand is about half of that. We simulate hourly demand profiles for the DE system using the Building America Simulation for a typical meteorological year for the Manhattan location (Wilson 2014). Our simulation of the aggregate DE system demand used hourly building profiles from large offices, midrise apartments, and large hotels. Figure B-9 shows the simulated demand profile for the DE system in Manhattan, which roughly aligns with the characteristics of ConEd's DE system.

In contrast to the college campus DE systems we assume cogeneration to supply 40 percent of steam in the Manhattan DE system and natural gas boilers to provide the remaining 60 percent (the college DE systems are not assumed to have cogeneration).[26] Natural gas prices vary monthly in NYISO and range from $4.58–$6.03 per million Btu (MMBtu), which includes a carbon price of $24 per ton.[27] In addition to production costs, we model the capital cost of 100 miles of distribution pipes in the Manhattan system to be approximately $320,000 per mile ($200 per meter) (Pensini, Rasmussen, and Kempton 2014). Assumptions which deviate from the college-campus examples are listed below in Table B-4.

Table B-4. Additional district energy assumptions for Manhattan

Assumption	Units	Value
Electric heat pump efficiency (COP) city-scale	%	300
Electric heat pump capacity in hybrid city-scale case	MW	500
Distribution pipe capital cost	$/mile	200
Distribution pipe losses	%	10
Distribution pipe installation cost	% of capital cost	25
Distribution pipe maintenance cost	% of capital cost	1
Distribution pipe lifetime	Years	25
City-scale district energy demand	MMlb/year	20,000
City-scale district energy peak demand	MMlb/hour	8.5
City-scale combination of simulated buildings to satisfy annual and peak demand	Number of buildings	2,288

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[26] In rare instances, ConEd's DE system supplies steam during peak hours via oil-fired boilers. We choose to model ConEd's existing system only using natural gas-fired assets for simplicity.

[27] Additional detail on natural gas price assumptions by month may be found above in Figure B-7 .

We assume a lower baseline coefficient of performance of 3.0 than in the college campus examples and test sensitivity cases of 1.5 and 4.5. Given the larger scale of the Manhattan DE system we assume an electric heat pump capacity of 500MW in the hybrid case, translating to about 20 percent of the system's peak demand.

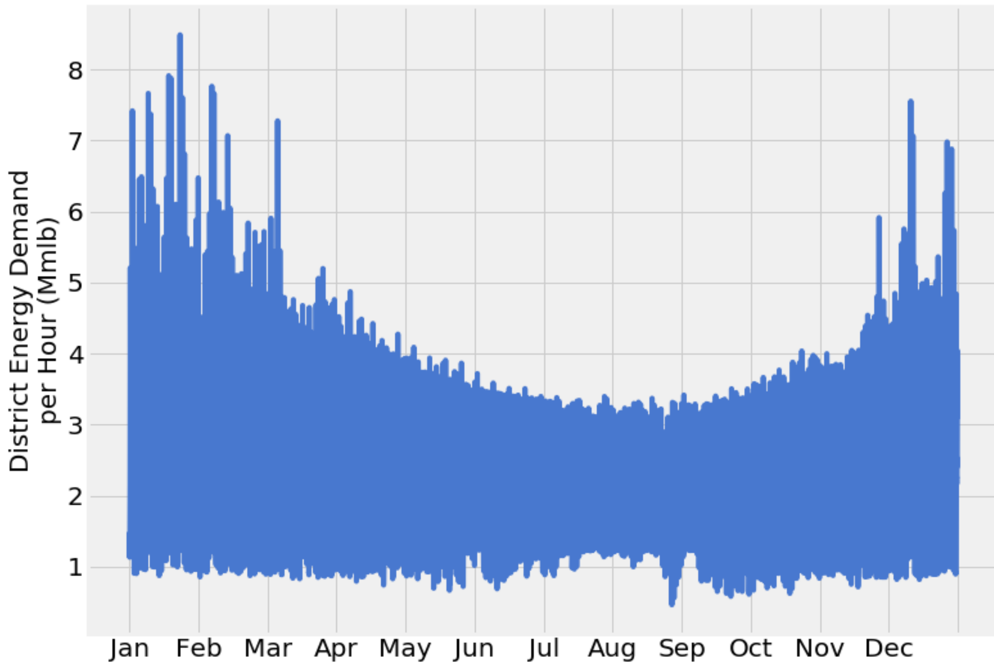

Figure B-9. Simulated hourly district energy demand for heating and cooling for the ConEd system

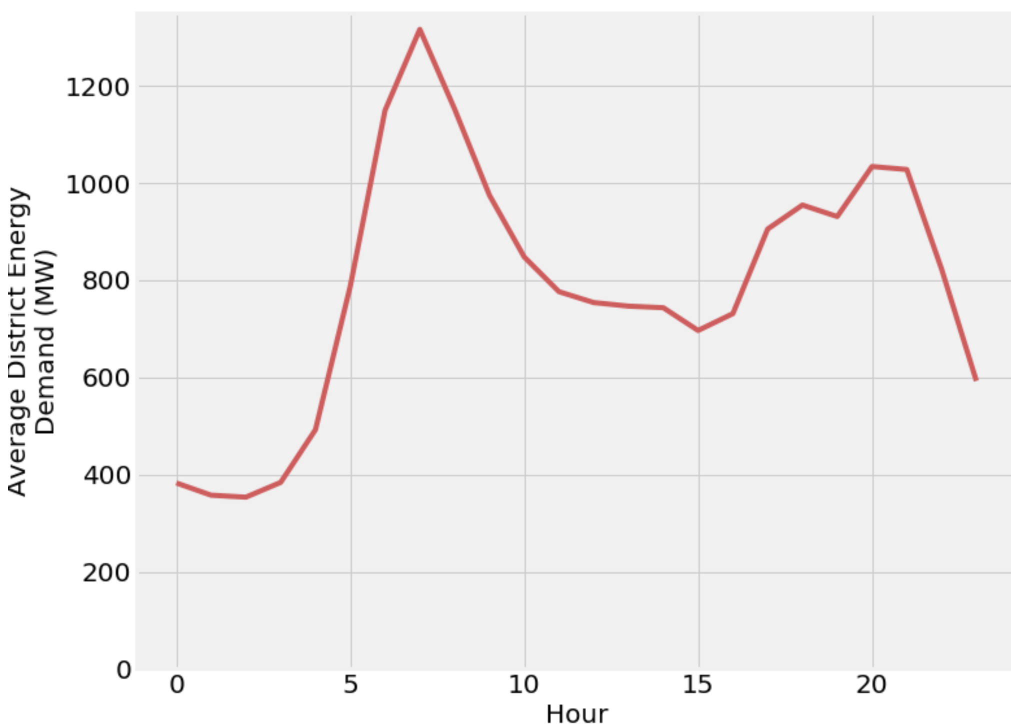

Figure B-10. Simulated hourly district energy demand for heating and cooling for the ConEd system

Findings

Supplementing ConEd's DE system with heat pumps in a hybrid setting appears not to be cost-effective in a low VRE scenario; however, the economics reverse in a high VRE environment.

Similar to the H_2 production assessment, the decision to supplement a production process with electricity input rests on the end user's trade-off between operating the electrical component more frequently to decrease per-unit capital costs versus operating it minimally to reduce exposure to higher and higher priced hours. However, the decision by the industrial end user to fuel-switch is more complicated than the electro-commodity case. Now, the end user may want to also consider the time-varying price of the competing fuel (e.g., natural gas), and in the case of DE, the customer could also consider the time-varying nature of system demand.

Figure B-11 plots the levelized cost of delivering steam over a range of utilization rates in the hybrid setting, which features supply from cogeneration, natural gas boilers, and 500 MW of electric heat pumps. Again, the vertical dashed lines intersect the scenario-specific levelized-cost curves at their respective minimums after accounting for cost increases in the first hour of the heat pump utilization, representing the incremental capital costs of the heat pump.

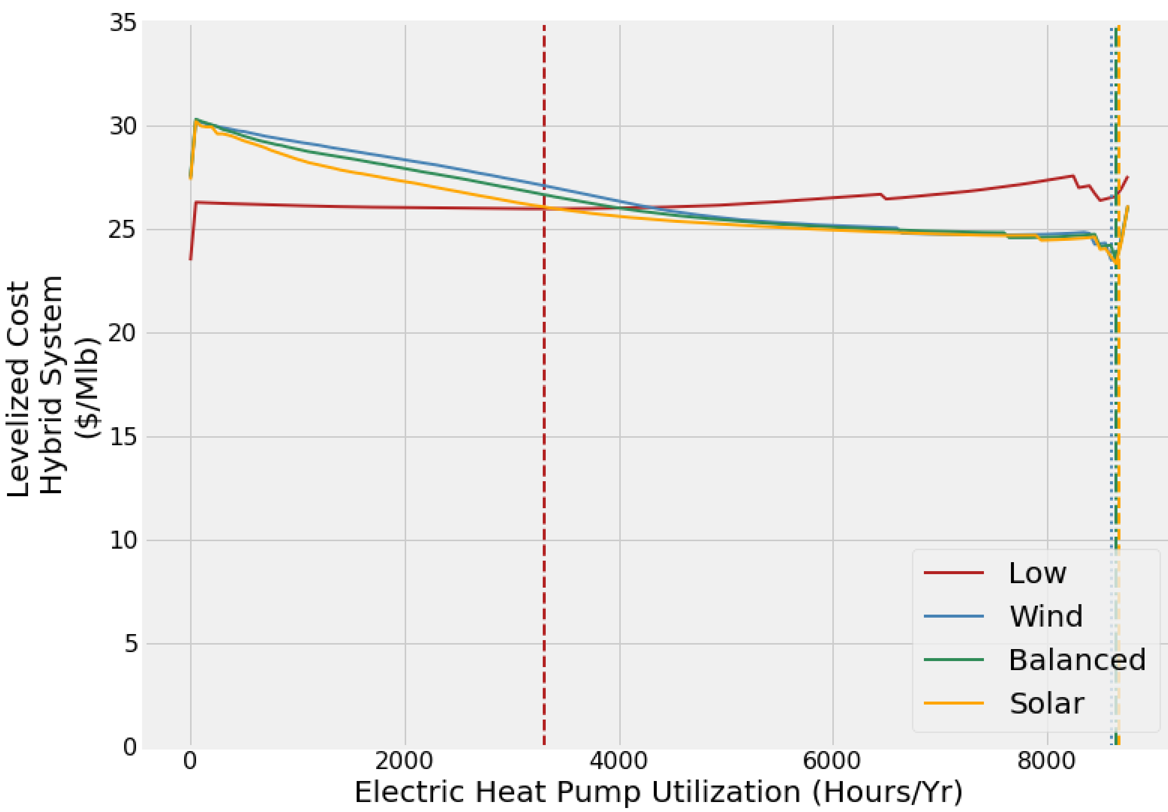

Figure B-11. Optimal heat pump utilization rates in a hybrid setting in ConEd's Manhattan DE system

In the low VRE scenario, the operator would deliver steam at the lowest cost with no supply from the 500 MW electric heat pump capacity. If forced to invest in a heat pump, delivered steam costs would rise by about $3 per thousand pounds (Mlb) of steam and the heat pump would be used for about 40 percent of all hours. In contrast, in each of the high VRE scenarios, the operator minimizes levelized cost at utilization rates of almost 100 percent. Electric heat pumps run during all hours of the year, except the top 2 percent of hours when electricity prices are at their peaks. The effect of peak electricity prices is represented by the sharp uptick in levelized cost at the right-hand side of Figure B-11.

The levelized-cost curves for the high VRE scenarios are shifted upward at a utilization of zero compared to the low VRE scenario. This means the cost of supplying steam only with cogeneration and gas boilers increases in high VRE scenarios, independent of the decision to supplement the system with electric heat pumps. This result is best understood by the realization that the levelized cost of supplying steam from cogeneration increases in a high VRE scenario because electricity prices and associated electricity revenue decrease, on average. One of the reasons cogeneration is a popular choice for DE systems is that its capital costs can be shared by both electricity and heating revenues. However, if electricity prices decrease in a high VRE scenario and associated cogeneration revenue (or opportunity costs) fall, this effect of spreading capital costs across electricity and heating revenues is diminished.

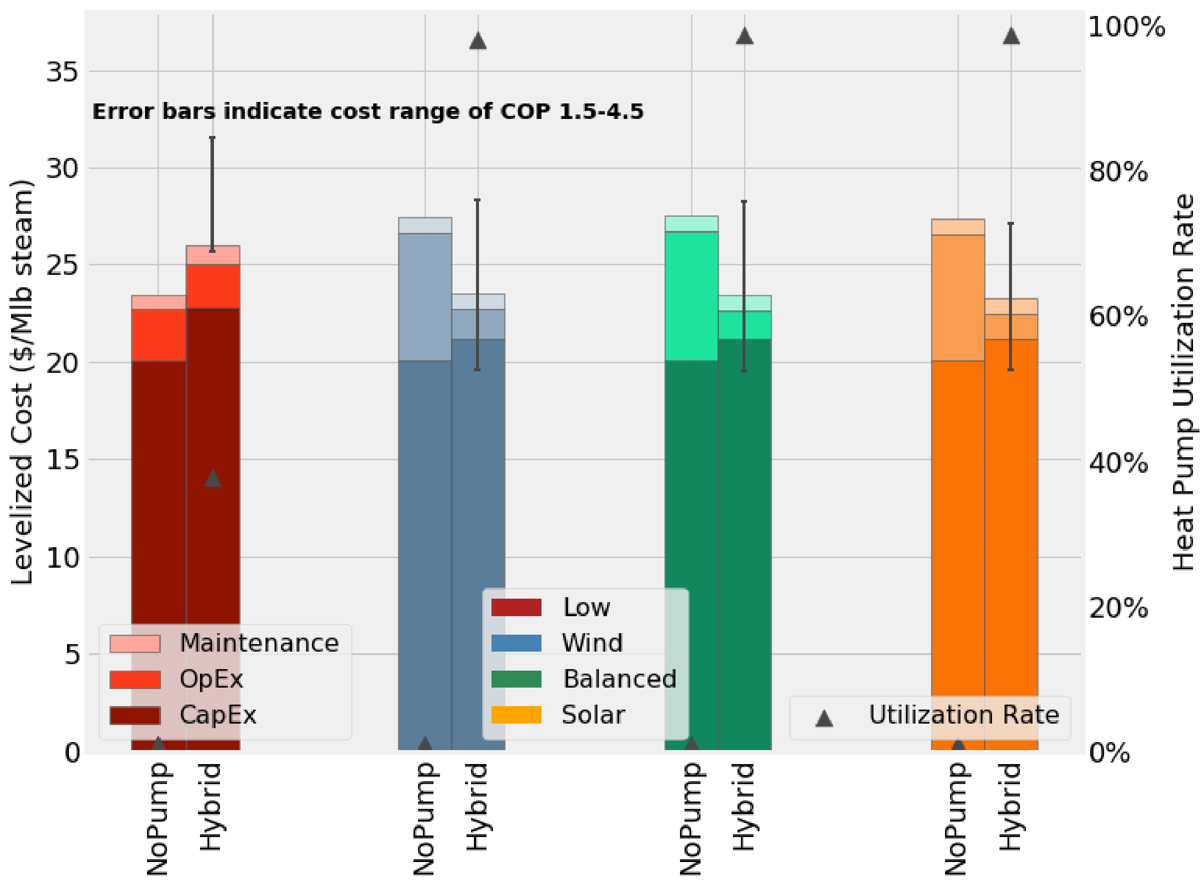

Figure B-12. Levelized energy costs for Manhattan's system across DE system configurations and scenarios

Figure B-12 summarizes the levelized-cost estimates pictured in Figure B-11 and compares the two scenarios: the all-gas system and the hybrid system. The bar results and utilization rates in the figure assume a COP of 3, while the error bars showcase the sensitivity of levelized costs to changes in COP assumptions (1.5 versus 4.5). The COP value depends both on the ambient air temperature and the temperature of the desired process heat, which is moderate in DE systems that use the steam for heating indoor spaces and water heating. As described already above, the hybrid system configuration leads to cost *increases* in the low VRE scenario but cost *decreases* in the high VRE scenario. Apart from the lower operating costs (driven by lower electricity prices) the capital cost contribution also decreases in the high VRE scenarios.

The higher heat pump utilization rates in the high VRE scenarios allow for the retirement of some natural gas boiler capacity, and the associated capital requirements fall. Table B-5 describes the relative cost-optimal installed capacities of natural gas cogeneration, natural gas boiler, and electric heat pump assets for the Manhattan DE system across the all-gas scenario (current status), and the hybrid scenario with a heat pump accounting for about 20 percent of the system's peak demand. In both cases, we assume a 10 percent reserve margin above the system's maximum demand to ensure that all heating needs will be met, provided by the lowest-cost capital resource, natural gas boilers. Required cogeneration and boiler capacity in the hybrid scenario are determined by the relative performance characteristics of the heat pumps; more efficient (higher COP) heat pumps enable more fossil capacity retirements relative to the all-gas scenario for the same rated nameplate heat pump capacity. Similarly, higher utilization rates of the heat pumps in the high VRE scenarios lead to further boiler retirements in the hybrid scenario, which in turn lower the overall system's CapEx contribution to the levelized heating costs, as shown in Figure B-12 above.

Table B-5. Total installed capacity of stylized Manhattan DE system by generation type

		Cogeneration (GW)			**Natural Gas Boiler (GW)**			**Electric Heat Pump (GW)**		
COP		*[1.5]*	*[3]*	*[4.5]*	*[1.5]*	*[3]*	*[4.5]*	*[1.5]*	*[3]*	*[4.5]*
All-Gas	All-Scenarios	3.3	3.3	3.3	2.6	2.6	2.6	0.0	0.0	0.0
Hybrid	Low	3.3	3.3	2.6	2.6	2.6	0.0	0.5	0.5	0.5
	Wind	3.3	3.3	2.7	2.3	0.6	0.0	0.5	0.5	0.5
	Balanced	3.3	3.3	2.7	2.6	0.6	0.0	0.5	0.5	0.5
	Solar	3.3	3.3	2.7	2.6	0.6	0.0	0.5	0.5	0.5

Appendix C. Electricity Retail Rate Design

The three tables below summarize rate characteristics with the lowest deadweight loss across scenarios and regions during the summer months (Table C-1), the non-summer months (Table C-2), and the associated deadweight loss on a per MWh basis and annual sum (Table C-3).

Table C-1. Efficient rate characteristics—summer months June 1 to September 30

	Southwest Power Pool				New York ISO				California ISO				ERCOT			
	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar
Peak/Off-Peak Price Ratio																
TOU2	4.5	4.5	4.5	5.0	2.5	3.8	4.2	5.3	6.0	3.9	4.6	6.0	5.5	5.5	9.5	7.6
TOU3	4.5	4.5	4.5	4.5	1.9	3.0	2.8	2.7	5.7	3.0	3.7	5.5	5.5	5.5	6.6	5.5
CPP + TOU	1.1	1.2	1.4	1.4	1.3	1.2	1.4	1.4	1.2	1.1	1.3	1.3	1.8	1.3	1.8	1.1
Super Off-Peak/Off-Peak Price Ratio																
TOU3	0.5	0.3	0.2	0.2	0.6	0.3	0.3	0.2	0.9	0.5	0.6	0.6	0.5	0.4	0.2	0.2
CPP + TOU	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	1.0	0.8	1.0	0.7	0.6	0.8	0.5	0.4
Critical Peak/Off-Peak Price Ratio																
CPP + TOU	15.5	23.5	25.1	27.3	5.8	16.5	18.5	19.5	13.3	11.5	13.5	13.5	14.5	25.5	30.5	30.5
Peak Period *(Hour Beg - Hour End)*																
TOU2	13-19	15-20	17-21	18-22	10-21	14-21	16-22	17-22	16-21	16-21	17-21	17-21	13-18	14-21	19-21	17-21
TOU3	13-19	16-20	18-21	18-21	13-21	15-20	17-21	18-21	16-21	16-21	17-21	17-21	13-18	14-21	19-21	17-21
Super Off-Peak Period *(Hour Beg - Hour End)*																
TOU3	0-11	0-13	0-16	0-17	0-8	0-10	0-15	0-16	0-13	0-14	0-15	9-14	0-11	0-12	0-16	1-16

Table C-2. Efficient rate characteristics—non-summer months October 1 to May 31

	Southwest Power Pool				New York ISO				California ISO				ERCOT			
	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar
Peak/Off-Peak Price Ratio																
TOU2	1.2	1.4	1.5	1.5	1.3	1.4	1.5	1.5	1.2	1.3	1.3	1.3	1.6	1.5	1.6	1.7
TOU3	1.0	1.3	1.4	1.4	1.2	1.3	1.4	1.5	1.2	1.3	1.2	1.2	1.6	1.5	1.5	1.7
CPP + TOU	1.0	1.3	1.4	1.4	1.2	1.3	1.4	1.5	1.2	1.3	1.2	1.2	1.6	1.5	1.5	1.7
Super Off-Peak/Off-Peak Price Ratio																
TOU3	0.8	0.9	0.7	0.5	0.8	0.8	0.9	0.7	1.0	0.8	0.7	0.4	0.9	0.9	0.7	0.6
CPP + TOU	0.8	0.9	0.7	0.5	0.8	0.8	0.9	0.7	1.0	0.8	0.7	0.4	0.9	0.9	0.7	0.6
Critical Peak/Off-Peak Price Ratio																
CPP + TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Period *(Hour Beg - Hour End)*																
TOU2	8-23	17-23	18-23	17-23	7-22	6-22	16-22	16-22	16-21	16-22	16-23	16-23	14-18	6-7	20-21	20-22
TOU3	7-8	17-23	18-23	18-23	18-19	16-21	16-22	17-22	17-21	16-22	17-22	17-22	14-18	6-7	20-21	21-22
Super Off-Peak Period *(Hour Beg - Hour End)*																
TOU3	1-6	1-15	9-15	9-15	0-6	0-6	9-14	9-14	10-14	10-14	9-14	10-14	0-6	9-15	9-16	11-16

Note: No CPP events are called during non-summer months.

Table C-3. Deadweight loss summary

	Southwest Power Pool				New York ISO				California ISO				ERCOT			
	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar	Low	Wind	Balanced	Solar
Load																
GWh per Year	303,820				160,912				247,683				446,071			
Deadweight Loss ($/MWh)																
Flat	3.3	6.5	6.9	7.3	0.5	3.9	3.9	4.4	3.4	2.8	2.8	3.0	3.9	6.5	13.7	22.6
TOU2	1.4	2.5	2.5	2.2	0.3	1.4	1.3	1.3	0.8	1.1	0.9	0.8	1.5	2.4	2.7	5.4
TOU3	1.3	2.1	1.9	1.7	0.3	1.3	1.1	1.2	0.8	1.0	0.8	0.7	1.4	2.2	2.2	4.5
CPP + TOU3	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.3	0.2	0.9	1.5
Deadweight Loss ($ millions)																
Flat	1,010	1,974	2,107	2,223	83	633	622	712	839	695	698	741	1,730	2,921	6,109	10,086
TOU2	435	767	755	664	42	231	212	211	198	268	226	192	683	1,066	1,188	2,424
TOU3	405	652	587	513	44	209	179	200	197	246	208	178	640	993	960	2,007
CPP + TOU3	6	20	27	33	4	14	19	23	3	34	29	37	119	76	406	691